ANNUAL INFORMATION FORM

For the Year Ended December 31, 2017

Dated March 20, 2018

TABLE OF CONTENTS

Page

ABBREVIATIONS AND CONVERSION	1
DEFINITIONS	2
PRESENTATION OF RESERVES AND RESOURCES INFORMATION	7
FORWARD-LOOKING STATEMENTS	9
VALEURA ENERGY INC.	13
GENERAL DEVELOPMENT OF THE BUSINESS	14
DESCRIPTION OF THE BUSINESS AND OPERATIONS	16
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION	21
PROSPECTIVE RESOURCES	22
DESCRIPTION OF CAPITAL STRUCTURE	23
DIVIDENDS	23
PRIOR SALES	23
MARKET FOR COMMON SHARES	23
DIRECTORS AND EXECUTIVE OFFICERS	24
AUDIT COMMITTEE	26
RISK FACTORS	27
INDUSTRY CONDITIONS	36
LEGAL AND REGULATORY PROCEEDINGS	38
INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS	38
TRANSFER AGENT AND REGISTRAR	38
MATERIAL CONTRACTS	38
INTERESTS OF EXPERTS	39
ADDITIONAL INFORMATION	39

APPENDIX A-1 – FORM 51-101F1 – STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

APPENDIX A-2 – PROSPECTIVE RESOURCES DATA

APPENDIX A-3 – FORM 51-101F2 – REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

APPENDIX A-4 – FORM 51-101F2 – REPORT ON PROSPECTIVE RESOURCES DATA BY AN INDEPENDENT QUALIFIED RESERVES EVALUATOR

APPENDIX A-5 – FORM 51-101F3 – REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

APPENDIX B – TERMS OF REFERENCE FOR THE AUDIT COMMITTEE

ABBREVIATIONS AND CONVERSION

In this Annual Information Form, the following abbreviations have the meanings set forth below.

Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
bbl/d	barrel per day
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMBtu	million British Thermal Units
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day

Other

BOE	barrel of oil equivalent.
BOE/d	barrel of oil equivalent per day.
BOTAS	Boru Hatlari ile Petrol Tasima Anonim Sirketi ("**BOTAS**") owns and operates the national crude oil pipeline grid and the national gas pipeline grid in Turkey. BOTAS regularly posts natural gas prices and its Industrial Interruptible Tariff benchmark is shown herein as a reference price.
M$	thousands of dollars.
MM$	millions of dollars.
McfGE	thousand cubic feet of sales gas equivalent.
NYMEX	New York Mercantile Exchange.
TL/m3	Turkish Lira per cubic metre.
TL	Turkish Lira.
$	Canadian dollars.
US$	U.S. dollars.
IP	Initial on-stream production rate.
psi	pounds per square inch.

Conversions

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units)

To convert to	From	Multiply by
1,000 cubic metres of gas	Mcf	35.494
bbl	cubic metres of oil	0.158
cubic metres of oil	bbl	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

DEFINITIONS

In this Annual Information Form, the following words and phrases have the meanings set forth below, unless otherwise indicated.

"**2016 Offering**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**2018 Offering**" has the meaning set forth under the heading "*General Development of the Business – Recent Developments*".

"**abandonment and reclamation costs**" means all costs associated with the process of restoring a reporting issuer's property that has been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities.

"**ABCA**" means the *Business Corporations Act* (Alberta), together with any or all regulations promulgated thereunder, as amended from time to time.

"**Barnali Farm-in**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**Banarli Licences**" means, collectively, the two Banarli licenses described under the heading "*Description of the Business and Operations – Licence Term and Commitments*".

"**BCGA**" means basin-centered gas accumulation.

"**Board**" means the board of directors of Valeura.

"**BOTAS Reference Price**" has the meaning set forth under the heading "*Risk Factors – Pricing and Marketing*".

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time.

"**Common Shares**" means the common shares in the capital of the Company.

"**Company**" or "**Valeura**" means Valeura Energy Inc. and, where applicable, includes its subsidiaries and affiliates.

"**CRBV**" means Corporate Resources B.V., a wholly-owned affiliate of Valeura.

"**crude oil**" or "**oil**" as described in the COGE Handbook means a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas.

"**D&M**" means DeGolyer and MacNaughton, independent petroleum engineering consultants.

"**D&M Reserves Report**" means the independent engineering evaluation of the oil and natural gas reserves attributable to the properties of Valeura in Turkey prepared by D&M with a preparation date of March 20, 2018 and effective December 31, 2017.

"**D&M Resources Report**" means the independent engineering evaluation of the unconventional prospective resources attributable to the properties of Valeura in the Thrace Basin prepared by D&M with a preparation date of February 6, 2018 and effective December 31, 2017.

"**Definitive Agreements**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying and acquiring well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"**Definitive Agreements**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**Edirne Leases**" means, collectively, the three production leases described under the heading "*Description of the Business and Operations – Licence Term and Commitments*".

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

"**exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**frac**" means hydraulic fracturing whereby fractures are propagated in an underground rock layer by injecting fluids, typically mixtures of sand and water, under high pressures.

"**field**" means a defined geographical area consisting of one or more hydrocarbon pools.

"**forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

"**forward-looking statements**" has the meaning set forth under the heading "*Forward-Looking Statements*".

"**future net revenue**" means a forecast of revenue, estimated using forecast prices and costs or constant prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs and abandonment and reclamation costs.

"**GDPA**" means the Republic of Turkey's General Directorate of Petroleum Affairs.

"**gross**" means:

(a) in relation to the Company's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company;

(b) in relation to wells, the total number of wells in which the Company has an interest; and

(c) in relation to properties, the total area of properties in which the Company has an interest.

"**ICFR**" has the meaning set forth under the heading "*Risk Factors – Internal Controls Over Financial Reporting*".

"**natural gas**" means a naturally occurring mixture of hydrocarbon gases and other gases.

"**natural gas liquids**" or "**NGLs**" means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates.

"**net**" means:

(a) in relation to the Company's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;

(b) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

"**New Petroleum Law**" means Turkey's Petroleum Law No. 6491 adopted in 2013 which replaced the Old Petroleum Law.

"**NI 51-101**" means National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities*.

"**Old Petroleum Law**" means Turkey's Petroleum Law No. 6326 adopted in 1954 which was replaced by the New Petroleum Law.

"**operating costs**" or "**production costs**" means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

"**Option**" means an option to acquire a Common Share pursuant to the Stock Option Plan.

"**Preferred Shares**" has the meaning set forth under the heading "*Description of Capital Structure*".

"**production**" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

"**property**" includes:

(a) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"**property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;

(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and

(c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

"**proved property**" means a property or part of a property to which reserves have been specifically attributed.

"**PTI**" means Pinnacle Turkey, Inc.

"**reservoir**" as described in the COGE Handbook means a subsurface rock unit that contains an accumulation of petroleum.

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

"**Shareholders**" means the holders of Common Shares and "**Shareholder**" means any one of them.

"**solution gas**" means gas dissolved in crude oil.

"**South Thrace Lands**" means, collectively, the lands comprising the South Thrace Production Leases.

"**South Thrace Production Leases**" means, collectively, the 11 South Thrace production leases described under the heading "*Description of the Business and Operations – Licence Term and Commitments*".

"**Statoil**" means Statoil Banarli Turkey B.V., a wholly-owned affiliate of Statoil ASA.

"**Stock Option Plan**" means the stock option plan of the Company.

"**stratigraphic test well**" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as:

(a) "exploratory type" if not drilled into a proved property; or

(b) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

"**Subsequent Deep Rights Sale Agreement**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**support equipment and facilities**" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

"**TBNG**" means Thrace Basin Natural Gas Turkiye Corporation, a wholly-owned affiliate of TWL prior to completion of the TBNG Acquisition and thereafter, a wholly-owned affiliate of Valeura.

"**TBNG Acquisition**" has the meaning set forth under the heading "*General Development of the Business-Three Year History*".

"**TBNG JV**" means the joint venture formed between CRBV, TBNG and PTI.

"**TBNG JV Lands**" means, collectively, the South Thrace Lands and the West Thrace Lands

"**Thrace Basin**" means an area of land in the northwest region of Turkey, located west of Istanbul and extending to the Greek and Bulgarian borders.

"**TPAO**" means Türkiye Petrolleri Anonim Ortaklığı, the Turkish state oil and gas company.

"**TransAtlantic**" means TransAtlantic Petroleum Ltd.

"**TSX**" means the Toronto Stock Exchange.

"**TWL**" means TransAtlantic Worldwide, Ltd., a wholly-owned affiliate of TransAtlantic.

"**U.S.**" or "**United States**" means the United States of America, its territories and possessions, any state of the United States, and the District of Columbia.

"**VENBV**" means Valeura Energy (Netherlands) B.V., a wholly-owned affiliate of Valeura.

"**well abandonment costs**" means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. These costs do not include costs of abandoning the gathering system or reclaiming the wellsite.

"**West Thrace Deep Rights Sale**" has the meaning set forth under the heading "*General Development of the Business – Three Year History*".

"**West Thrace Lands**" means, collectively, the lands comprising the West Thrace Licenses and the West Thrace Production Leases.

"**West Thrace Licenses**" means, collectively, the two West Thrace licenses described under the heading "*Description of the Business and Operations – Licence Term and Commitments*".

"**West Thrace Production Leases**" means, collectively, the three West Thrace production leases described under the heading "*Description of the Business and Operations – Licence Term and Commitments*".

PRESENTATION OF RESERVES AND RESOURCES INFORMATION

All oil and natural gas reserves and resources information contained in this Annual Information Form has been prepared and presented in accordance with NI 51-101 and the COGE Handbook. The reserves and prospective resource estimates provided in this Annual Information Form are estimates only. Actual reserves and prospective resources and future production from such reserves and resources may be greater than or less than the estimates provided herein.

Numbers in the reserves and resources tables and other oil and gas information contained in this Annual Information Form may not add due to rounding.

Definitions

With respect to the reserves and resources data contained herein, the following terms have the meanings indicated:

"**best estimate**" or "**P50**" means there is a 50% chance that the estimated quantity will be equaled or exceeded.

"**chance of commerciality**" is defined as the product of the chance of discovery and the chance of development.

"**chance of development**" is the estimated probability that, once discovered, a known accumulation will be commercially developed.

"**chance of discovery**" is the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum.

"**developed**" reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production.

"**developed producing**" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"**developed non-producing**" reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

"**high estimate**" or "**P10**" means there is a 1% chance that the estimated quantity will be equaled or exceeded.

"**low estimate**" or "**P90**" means there is a 90% chance that the estimated quantity will be equaled or exceeded.

"**mean estimate**" is the probability-weighted average (expected value).

"**possible**" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

"**probable**" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

"**prospective resources**" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development.

"**proved**" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

"**reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

"**resources**" are petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced. Total resources is equivalent to total petroleum initially-in-place.

"**undeveloped**" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Use of Unrisked Estimates

The unrisked estimates of prospective resources referred to in this Annual Information Form have not been risked for either the chance of discovery or the chance of development. There is no certainty that any portion of the prospective resources will be discovered. See "*Appendix A-2 – Prospective Resources Data*" for details regarding risked estimates. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development or that it will be commercially viable to produce any portion of the prospective resources.

BOEs

A BOE is determined by converting a volume of natural gas to barrels using the ratio of 6 Mcf to one barrel. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Further, a conversion ratio of 6 Mcf:1 BOE assumes that the gas is very dry without significant natural gas liquids. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Short Production Test Rates

The short production test rates disclosed in this Annual Information Form are preliminary in nature and may not be indicative of stabilized on-stream production rates. Initial on-stream production rates are typically disclosed with reference to the number of days in which production has been measured. Initial on-stream production rates are not necessarily indicative of long-term performance or ultimate recovery. To date, Valeura's shallow gas conventional wells and fraced unconventional tight gas wells have exhibited relatively high decline rates at more than 50% and 75%, respectively, in their first year of production.

There is currently no long-term flow information for the deep, unconventional BCGA play discovered with Yamalik-1. While the same geological formations that are producing gas in the shallow are being targeted in the deep, unconventional play, they are in a different depth and pressure environment and the type curves are not expected to be indicative of Yamalik-1 future production, or any other future deep, unconventional well. A pressure transient analysis or well-test interpretation has not been carried out in respect of the production tests on the Yamalik-1 well. All natural gas rates and volumes are presented net of any load fluids.

FORWARD-LOOKING STATEMENTS

Certain information contained in this Annual Information Form constitutes forward-looking statements and forward-looking information (collectively, "**forward-looking statements**") under applicable securities legislation. Such forward-looking statements are included for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such forward-looking statements may not be appropriate for other purposes, such as making investment decisions. Forward-looking statements typically include words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "target", "goal", "propose", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this Annual Information Form include, but are not limited to, statements with respect to:

- management's belief regarding the potential of Valeura's BCGA play and shallow gas business in the Thrace Basin;
- the potential of a BCGA play in the Thrace Basin;
- Valeura's reserves and prospective resources in the Thrace Basin;
- the anticipated delineation drilling and development program to exploit the BCGA play on Valeura's working interest lands;
- completion of Phase 3 of the Banarli Farm-in and drilling of the second earning well to be funded by Statoil;
- the ability to target sweet spots in the BCGA prospect and the extent of the prospect;
- the plans to drill to 5,000 metres in the BCGA prospect delineation program and the cost and timeline impacts;
- the plans, timelines and cost to tie-in the Yamalik-1 well to conduct a long term production test, establish production type curves and achieve gas sales;
- the final cost and timeline to complete the processing of the Karaca 3D seismic and early fast-track processing step to facilitate planning;
- the anticipated conventional tight gas development program in the Tekirdag field that underpins Valeura's current probable and possible reserves;

- the capacity of Valeura's existing infrastructure in the Thrace Basin should future production volumes exceed the capacity of Valeura's existing infrastructure;

- Valeura's commitment to safety and optimizing operational and administrative functions;

- Valeura's business strategy and outlook;

- the ability to execute and agree with partners on work programs (and the nature and extent of such work programs) and budgets, which are subject to change based on, amongst other things, the actual results of drilling and related activity, the availability of equipment and service providers, unexpected delays and changes in market conditions;

- the ability to finance future developments;

- tying-in other new wells and getting these on-stream;

- results of future seismic programs;

- future production rates and associated cash flow;

- continued operations of and approvals forthcoming from the GDPA in a manner consistent with past conduct;

- future economic conditions;

- future currency and exchange rates;

- the Company's continued ability to obtain and retain qualified staff, and equipment and services in a timely and cost efficient manner;

- technical decision making;

- the ability to obtain necessary government and stock exchange approvals;

- volume and product mix of Valeura's natural gas and oil production;

- the amount and timing of future asset retirement obligations;

- future liquidity, creditworthiness and financial capacity;

- future interest rates;

- future exploration, development and other expenditures; and

- future costs, expenses and royalty rates.

Statements related to "reserves" or "prospective resources" are deemed to be forward-looking information as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and prospective resources can be profitably produced in the future. Specifically, forward-looking information contained herein regarding "reserves" and "prospective resources" may include:

- estimated volumes and value of Valeura's oil and natural gas reserves;

- estimated volumes of Valeura's prospective resources; and

- the ability to finance future developments.

Forward-looking statements are based on a number of factors and assumptions which have been used to develop such statements but which may prove to be incorrect. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this Annual Information Form, assumptions have been made regarding and are implicit in, among other things:

- the ability of the Company to execute its strategy;
- political stability of the areas in which Valeura is operating and completing transactions, and in particular the aftermath of the July 2016 failed coup attempt in Turkey and April 2017 constitutional referendum;
- the ability of the Company to satisfy the drilling and other requirements under its licences and leases;
- the ability of the Company to replace and expand oil and natural gas reserves through exploration, exploitation, development and acquisition;
- continued operations of and approvals forthcoming from the Turkish government in a manner consistent with past conduct;
- future seismic and drilling activity on the expected timelines;
- the prospectivity of the TBNG JV Lands and Banarli Licences, including the BCGA potential;
- the continued favourable pricing and operating netbacks in Turkey;
- future production rates and associated operating netbacks and cash flow;
- the ability to reach agreement with partners;
- the ability of the Company to successfully manage the political and economic risks inherent in pursuing oil and gas opportunities in Turkey;
- field production rates and decline rates;
- the ability of the Company to secure adequate product transportation;
- the impact of increasing competition in or near the Company's plays;
- the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner to develop its business and execute work programs;
- the Company's ability to operate the properties in a safe, environmentally responsible, efficient and effective manner;
- the timing and costs of pipeline, storage and facility construction and expansion;
- future oil and natural gas prices;
- currency, exchange and interest rates;

- the regulatory framework regarding royalties, taxes and environmental matters;
- the ability of the Company to successfully market its oil and natural gas products;
- the ability to successfully manage the political and economic risks inherent in pursuing oil and gas opportunities in foreign countries;
- the state of the capital markets; and
- the ability of the Company to obtain financing on acceptable terms.

Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used.

In addition, Valeura's work programs and budgets are in part based upon expected agreement among joint venture partners and associated exploration, development and marketing plans and anticipated costs and sales prices, which are subject to change based on, among other things, the actual results of drilling and related activity, availability of drilling, fracing and other specialized oilfield equipment and service providers, changes in partners' plans and unexpected delays and changes in market conditions. Although Valeura believes the expectations and assumptions reflected in such forward-looking information are reasonable, they may prove to be incorrect.

Forward-looking statements involve significant known and unknown risks and uncertainties. Exploration, appraisal, and development of oil and natural gas reserves are speculative activities and involve a significant degree of risk. A number of factors could cause actual results to differ materially from those anticipated by the Company including, but not limited to:

- the risks associated with the oil and gas industry (e.g. operational risks in exploration, inherent uncertainties in interpreting geological data, and changes in plans with respect to exploration or capital expenditures, the uncertainty of estimates and projections in relation to costs and expenses, and health, safety and environmental risks);
- uncertainty regarding the contemplated timeslines for the Yamalik-1 tie-in program;
- completion of the Banarli Farm-in program and BCGA delineation drilling program;
- uncertainty regarding the sustainability of initial production rates and decline rates thereafter;
- uncertainty regarding the ability to address technical drilling challenges and manage water production; uncertainty regarding the state of capital markets and the availability of future financings;
- the risk of being unable to meet drilling deadlines and the requirements under licences and leases;
- uncertainty regarding the availability of drilling rigs and associated equipment on the contemplated timelines for shallow and deep drilling programs;
- the risks of disruption to operations and access to worksites, threats to security and safety of personnel and potential property damage related to political issues, terrorist attacks, insurgencies or civil unrest;
- the risks of increased costs and delays in timing related to protecting the safety and security of Valeura's personnel and property;
- political stability in Turkey, including potential changes in political leaders or parties or a resurgence of a coup or other political turmoil;
- the risk of changing commodity prices and BOTAS Reference Prices (priced in TL);

- the risk of foreign exchange rate fluctuations, particularly the TL;
- the uncertainty associated with negotiating with third parties in Turkey;
- the risk of partners having different views on work programs and potential disputes among partners;
- counterparty risks;
- the uncertainty regarding government and other approvals (potential changes in laws and regulations);
- the risks associated with weather delays and natural disasters; and
- the risk associated with international activity.

The forward-looking statements contained herein are expressly qualified by this cautionary statement.

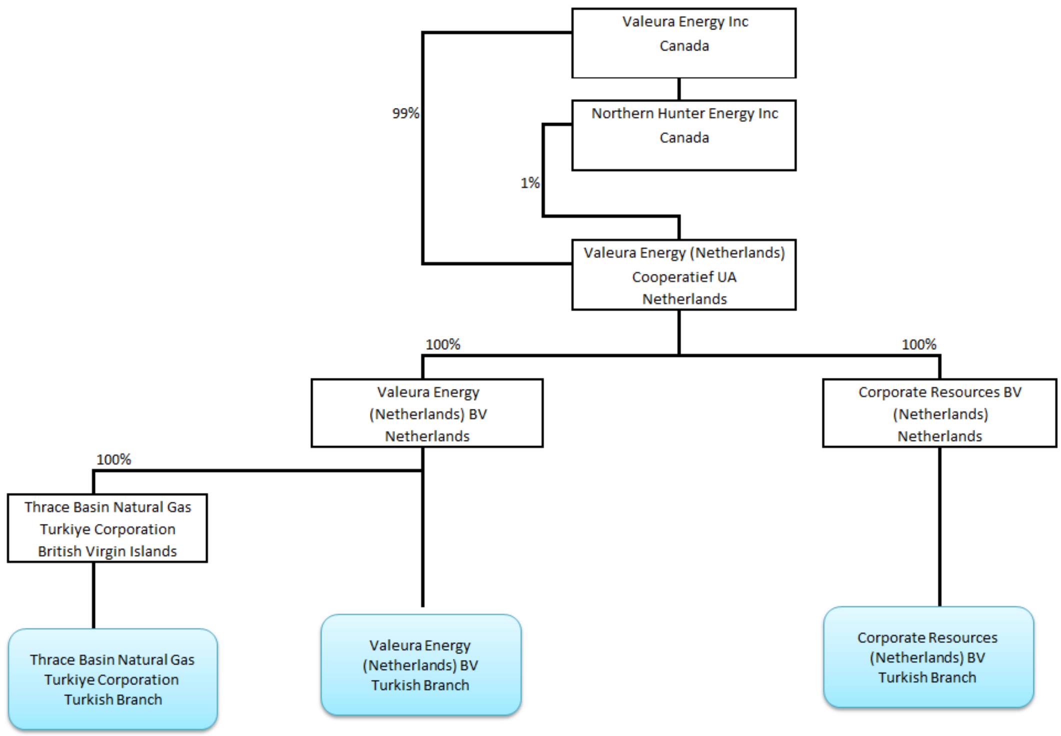
The forward-looking statements contained herein are made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking statement, whether as a result of new information, future events or otherwise, unless required by applicable securities laws.

VALEURA ENERGY INC.

Valeura and its subsidiaries are currently engaged in the exploration, development and production of oil and natural gas in Turkey. Valeura's operations are focused on the Thrace Basin in the northwest of Turkey. The Common Shares are listed and posted for trading on the TSX under the symbol VLE. The head office of Valeura is located at Suite 1200, 202 – 6th Avenue SW, Calgary, Alberta, T2P 2R9 and its registered and records office is located at 4600, 525 – 8th Avenue SW, Calgary, Alberta, T2P 1G1. Valeura was incorporated under the ABCA.

Inter-Corporate Relationships

The following diagram describes the inter-corporate relationships among the Company and each of its subsidiaries as at December 31, 2017:



GENERAL DEVELOPMENT OF THE BUSINESS

Valeura's operations are focused on the Thrace Basin in the northwest of Turkey. Valeura currently holds working interests in 21 production leases and exploration licenses covering approximately 0.53 million gross acres (0.43 million net acres of shallow rights and 0.28 million net acres of deep rights).

The Thrace Basin assets include an 81.5% working interest in the shallow rights and deep rights of 11 production leases in the South Thrace Lands; an 81.5% (shallow rights) working interest and 31.5% (deep rights) working interest in three production leases and two exploration licenses in the West Thrace Lands; and a 100% (shallow rights) and a 50% (deep rights) working interest in the Banarli Licenses. In addition, Valeura holds a 35% working interest in three other production leases (Edirne, Turkey) that currently do not have active operations. See "*Description of the Business and Operations – Land Holdings*".

TBNG has been producing natural gas from shallow, conventional and tight reservoirs for several decades. More than 99% of Valeura's current production is natural gas from these reservoirs. Management believes the Thrace Basin lands have potential for continued exploration and development of gas from these conventional and tight gas reservoirs. Valeura continues to work on its shallow gas development program associated with the proved plus probable reserves disclosed herein.

Management also believe that some or all of its Thrace Basin lands have potential for an unconventional BCGA in deep over-pressured formations below approximately 2,500 metres. Data from seven historic deep wells supported this BCGA thesis and in 2017, Valeura drilled, completed and flow-tested the Yamalik-1 gas-condensate discovery well. Yamalik-1 on the Banarli Licences proved the presence of a BCGA concept in the area of the well and the Company will be focused on appraising and proving the commerciality of this play in 2018 and 2019.

Three Year History

The following describes the development of Valeura's business over the last three completed financial years.

2015

Through the course of 2015, a number of additional exploration licence conversions were approved by the GDPA including two TBNG JV licences and Banarli licence 5104, which was converted into the Banarli Licences. Also, seven new TBNG JV production lease applications were approved by the GDPA.

In the second quarter of 2015, Valeura initiated the exploration program on the Banarli Licences and completed 152 square kilometres of 3D seismic, which positioned the Company to drill two exploration wells (Valeura 100% working interest) in November and December 2015. The first of these wells, Bati Gugen-1, was successfully production tested in December 2015 and was confirmed as a natural gas discovery. The second well Yayli-1 was cased in late December 2015.

2016

In the first quarter of 2016, the Bati Gurgen-1 well was tied into the TBNG JV gas gathering system. Two small fracs were carried out on the Yayli-1 well in tight, over-pressured sands near the base of the well at 2,700 to 2,900 metres, each of which achieved initial gas flow, but flow could not be sustained. The Yayli-1 well provided important information on the BCGA play.

In the second quarter of 2016, the Bati Gurgen-2 well was drilled and tied into the TBNG JV gas gathering system.

On August 19, 2016, Valeura announced that CRBV had entered into definitive transaction documents (the "**Definitive Agreements**") with Statoil for a farm-in agreement for the exploration of the deeper formations below approximately 2,500 meters on the Banarli Licences (the "**Barnali Farm-in**"). The Definitive Agreements included a farm-in agreement, a joint operating agreement to apply post-earning and a number of ancillary agreements. Under the terms of the Definitive Agreements, Statoil has the option to earn a 50% participating interest in the deep formations on the Banarli Licences by investing in an exploration program that includes cash payment and full funding of two deep exploration wells and 3D seismic costs at a minimum total spend of US$36 million. See "*Description of the Business and Operations – Land Holdings*".

On November 3, 2016, Valeura announced the closing of a private placement offering of subscription receipts at a price of $0.75 per subscription receipt for gross proceeds of approximately $10.9 million (the "**2016 Offering**"). The subscription receipts were sold through a syndicate of underwriters led by Cormark Securities Inc. and including GMP FirstEnergy.

2017

On January 6, 2017, Valeura announced the closing of the Banarli Farm-in and that it had received US$6.0 million in up-front payments as a contribution to back costs incurred on the Banarli Licenses.

On January 6, 2017, Valeura announced the closing of the sale to Statoil of a 40% participating interest in the deep formations below approximately 2,500 metres depth on the West Thrace Lands for cash consideration of US$12 million (the "**West Thrace Deep Rights Sale**") pursuant to the sale and purchase agreement dated October 13, 2016 between CRBV and Statoil.

On February 24, 2017, Valeura announced the closing of the acquisition of 100% of the shares of TBNG for US$20.7 million (CAD$27.1 million) (the "**TBNG Acquisition**") pursuant to the share purchase agreement dated October 13, 2016 between VENBV and TransAtlantic.

On June 22, 2017, Valeura announced the closing of the sale to Statoil of a further 10% participating interest in the deep formations below approximately 2,500 metres depth on the West Thrace Lands for cash consideration of US$3 million pursuant to the sale and purchase agreement dated March 10, 2017 between TBNG and Statoil (the "**Subsequent Deep Rights Sale Agreement**").

In the third quarter of 2017, Valeura completed approximately 500 square kilometres of 3D seismic, which is expected to provide Valeura and its partners with almost complete coverage of the target area of the BCGA play fairway. The 3D seismic survey was funded by Statoil and fulfilled Statoil's Phase 2 obligations under the Banarli Farm-in. Early "fast track" processing was delivered prior to year-end and final processed data are expected at end of Q1 2018.

On July 24, 2017, Valeura announced that the first deep exploration well, Yamalik-1, under Phase 1 of the Banarli Farm-in, was drilled to a total depth of 4,196 metres. Interpretation of the drilling and petrophysical data from Yamalik-1 suggested that the reservoir sections of the well were highly overpressured and gas saturated below approximately 2900 metres. In the fourth quarter of 2017, Valeura completed four production tests in the Kesan formation where each test was proceeded by two slick-water fracs. The 24-hour aggregate production test rate from the four production tests was 2.9 MMcf/d. Additionally, the gas flowed with a significant amount of condensate (range of 20 to 70 barrels per MMcf). The testing program achieved the objective of demonstrating that fracing would allow gas to flow to surface from these deep, tight reservoirs, and without the production of significant formation water. Both of these factors are key components to demonstrate the presence of an unconventional BCGA play. See "*Description of the Business and Operations – BCGA Play.*"

Subsequent Developments

On February 6, 2018, Valeura announced the summary results of the prospective resources evaluated by D&M in the D&M Resources Report summarized in Appendix A-2.

On March 1, 2018, Valeura announced that the closing of a public offering of 10,527,000 Common Shares at a price of $5.70 per Common Share for gross proceeds of approximately $60.0 million (the "**2018 Offering**"). The Common Shares were sold through a syndicate of underwriters led by GMP FirstEnergy and including Cormark Securities Inc.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

Valeura is a Canada-based public company currently engaged in the exploration, development and production of oil and natural gas in the Thrace Basin of northwest Turkey.

Corporate Strategy

The Company is focused on growing its established business in Turkey, particularly its natural gas operations in the Thrace Basin which yields very high natural gas prices relative to North America. The asset and financing deals completed by the Company between Q4 2016 and Q1 2018 have transformed the Company by increasing the size of the asset base, giving Valeura operatorship of all key assets, and providing the financial capacity to fully explore and appraise the unconventional BCGA play. Additionally, the Company has partnered with Statoil as a large, well-respected partner which provides further technical and financial capacity.

Valeura is currently focused on two key objectives:

- further delineation and commercial demonstration of the unconventional BCGA play discovered by the Yamalik-1 well in 2017; and

- continuing to optimize established conventional shallow gas assets in the Thrace Basin.

As a result of the success of the Yamalik-1 well, the primary focus of Valeura's business has transitioned from shallow gas development drilling to the definition and development of a deep unconventional BCGA play.

Personnel

As at December 31, 2017, Valeura had ten full-time employees in its head office in Calgary, as well as 16 full-time employees in its office in Ankara, Turkey and 62 employees at its field office in Teikerdag, Turkey.

Land Holdings

The following table and figure below set forth Valeura's land holdings as at December 31, 2017:

Valeura Working Interest Lands		Operatorship	Number of Production Leases & Exploration Licences	Gross Acres	Valeura Shallow Rights		Valeura Deep Rights	
					WI (%)	Net Acres	WI (%)	Net Acres
TBNG JV Lands	South Thrace Production Leases	Operated	11	170,737	81.5	139,151	81.5	139,151
	West Thrace Production Leases	Operated	3	13,578	81.5	11,066	31.5	4,277
	West Thrace Licences	Operated	2	160,468	81.5	130,781	31.5	50,547
Banarli Licences(1)(2)		Operated	2	133,840	100.0	133,840	50.0	66,920
Edirne Production Leases		Non-Operated	3	49,883	35.0	17,459	35.0	17,459
Total			**21**	**528,506**		**432,297**		**278,354**

Notes:

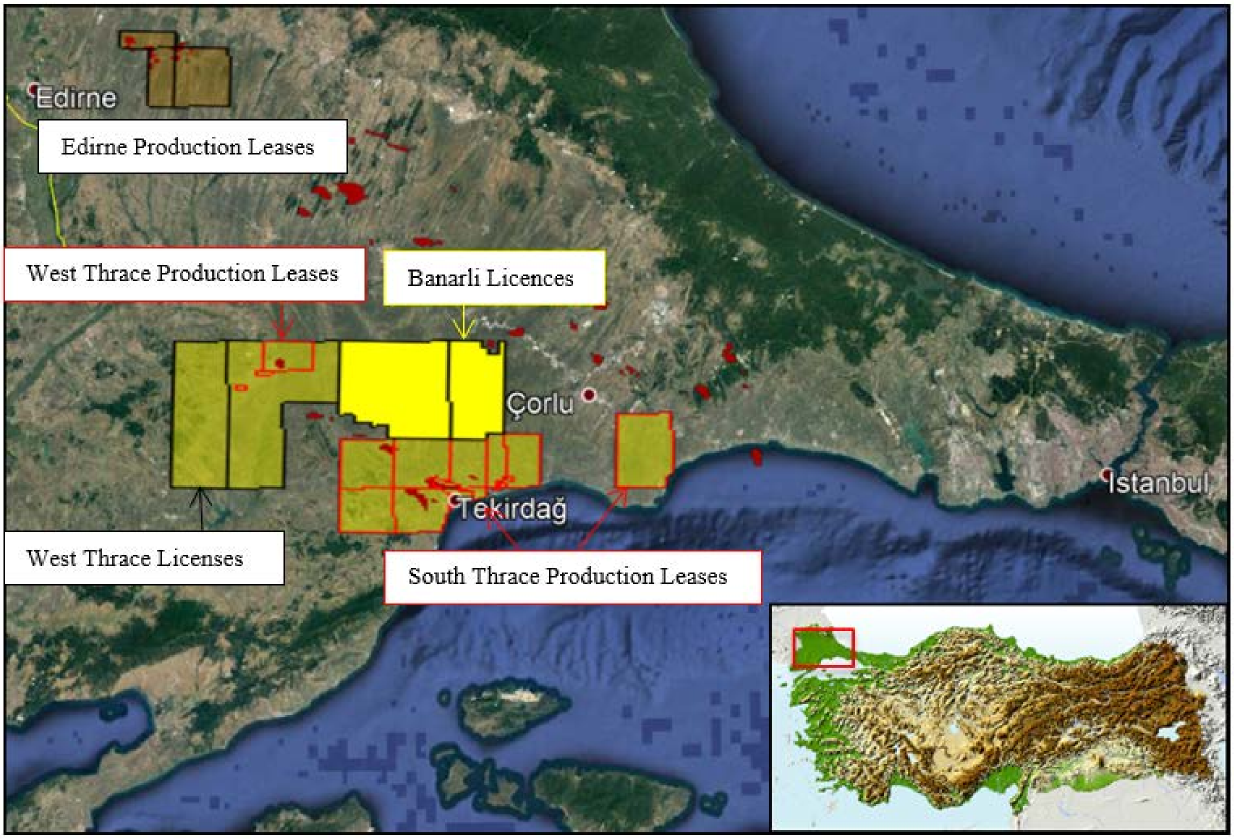
(1) Assumes Statoil completes its earning of a 50% working interest in the deep rights on the Banarli Licenses.

(2) The gross and net acreage shown includes 9,981 acres in the northeast corner of F19-d1, d4 that could potentially revert to TPAO. Since the Banarli Licenses were awarded to Valeura in 2015, the GDPA have supported Valeura's right to this area and Valeura has a legal opinion that is also supportive of its rights.

As of the date hereof, Valeura, through its interests in the TBNG JV, holds 14 production leases and two exploration licences encompassing 344,783 million gross acres. TBNG is the operator of the TBNG JV Lands comprising the South Thrace Production Leases, West Thrace Production Leases and West Thrace Licenses.Valeura holds an 81.5% working interest in the shallow rights on all of these lands, and a 31.5% interest in the deep rights on the West Thrace Production Leases and West Thrace Licenses. See "*General Development of the Business - Three Year History*".

As of the date hereof, Valeura holds two Banarli exploration licences (Valeura 50% operated working interest) encompassing 133,840 gross acres. Valeura will operate the deep exploration program on the Banarli Licences during Statoil's earning phase of the Banarli Farm-in and fully retains a 100% working interest in the shallow formations on the Banarli Licences. Under the Banarli Farm-in, to earn its 50% working interest Statoil must fully fund: (1) the drilling and testing of the Yamalik-1 well; (2) the acquisition and processing of the Karaca 3D seismic program; and (3) the drilling and testing of one more deep exploration well. If this work is not fully completed, there are financial penalties and 100% ownership of deep rights reverts to Valeura. As of the date hereof, Statoil has completed requirements (1) and (2). See "*General Development of the Business – Three Year History*".

As of the date hereof, Valeura and its joint partners hold three production leases (Valeura 35% working interest) in the Thrace Basin comprising the Edirne Leases encompassing 49,883 gross acres. An affiliate of TransAtlantic operates the Edirne assets. These leases had no sales or other activity in 2017.



Licence Term and Commitments

The initial term of the West Thrace Licenses expires on June 27, 2020. During the initial term, the TBNG JV is required to complete 100 square kilometres of 3D seismic and drill nine wells with a depth range of 850 to 2,000 metres. There are five wells remaining on these commitments, one to be completed by June 27, 2018, two by June 27, 2019 and two by June 27, 2020.

The initial term of the Banarli Licences expires on June 27, 2020. During the initial term of the Banarli Licences, the Company is required to complete 152 square kilometres of 3D seismic and drill three wells, including a 2,000 metre well in each of year one and year two and a 3,800 metre well in year four. As of the date hereof, all the required commitments have been met.

The following table sets forth the current expiration dates for Valeura's leases and licenses.

Valeura Working Interest Lands	Lease/License number	Period	Expiry Date
South Thrace Production Leases	3860	Initial Production	December 2, 2021
	3861	Initial Production	December 2, 2023
	F18-c3-1	Initial Production	November 10, 2023
	F18-c4-2	Initial Production	November 10, 2026
	F19-d4-1	Initial Production	November 10, 2022
	F19-d4-2	Initial Production	November 8 2020
	G19-a1-1	Initial Production	May 20, 2023
	G18-b2-1	Initial Production	September 10, 2023
	G18-b1-1	Initial Production	October 14, 2020

Valeura Working Interest Lands	Lease/License number	Period	Expiry Date
	F19-d3-1	Initial Production	November 5, 2020
	F19-c3-1	Initial Production	December 9, 2020
West Thrace Production Leases	2926	First Extension	February 16, 2020
	3659	First Extension	June 8, 2027
	5122	Initial Production	November 15, 2029
West Thrace Licenses	F17 c2-c3	Initial Exploration	June 27, 2020
	F18-d1,d2,d4	Initial Exploration	June 27, 2020
Banarli Licenses	F18-c1,c2,c3,c4	Initial Exploration	June 27, 2020
	F19-d1,d2	Initial Exploration	June 27, 2020
Edirne Production Leases	E17-b4-1	Initial Production	October 31, 2021
	E17c1-1	Initial Production	October 31, 2019
	E17-c2-1	Initial Production	October 31, 2020

An initial exploration license term is five years and may be extended for up to two 2-year terms, for a total of nine years, upon acceptance of an associated work plan. A third exploration period of 2 years can be awarded in the case of a discovery. This third two year extension forms the first two years of a production lease term if the exploration license is converted to a production lease.

Production leases have an initial term of up to 20 years, the actual term being determined by the GDPA as a reflection of resource life. Production leases may be extended twice for a term of up to 10 years per extension, again the actual term being determined by the GDPA as a reflection of resource life.

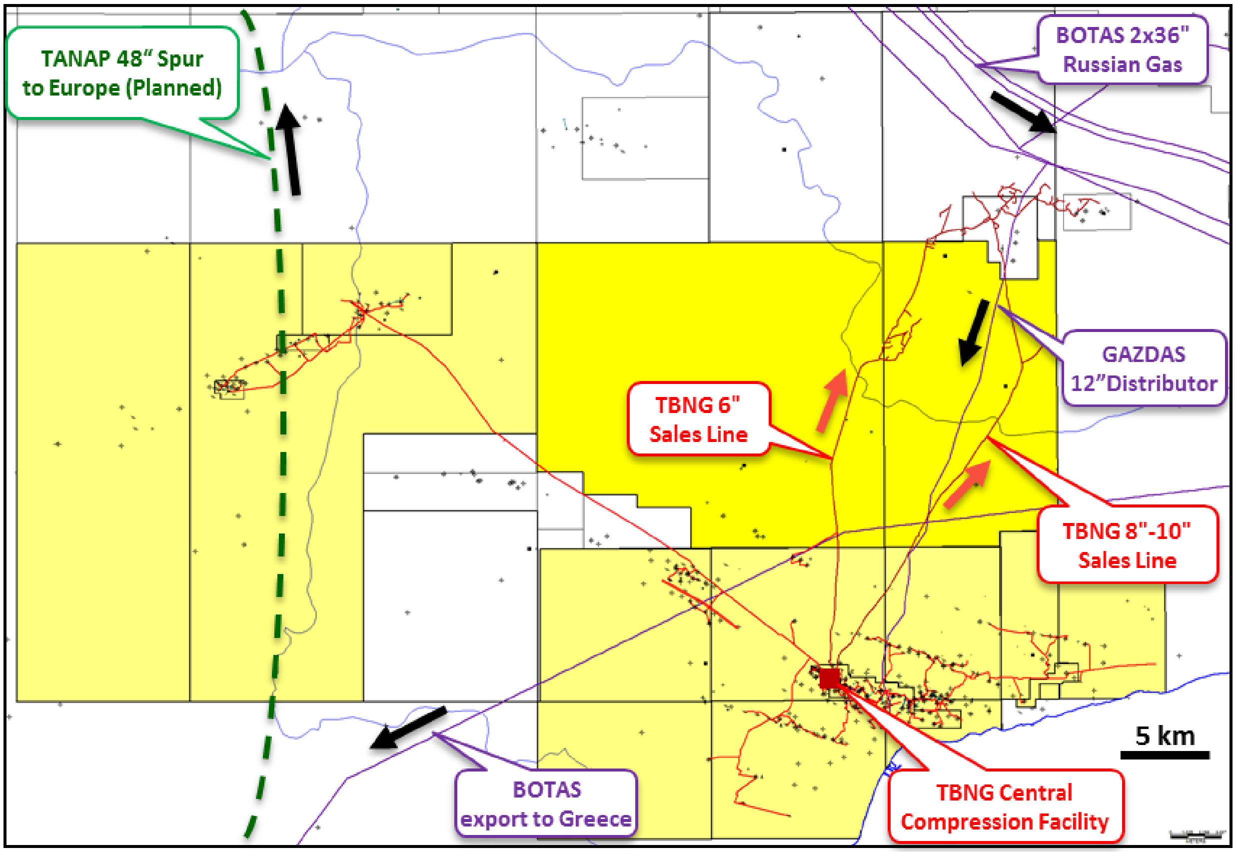
Petroleum Sales

All of Valeura's production is natural gas produced in the Thrace Basin. Total gross and net sales are shown in the table below.

		Gross Sales		Net Sales	
Lands	**Working Interest (%)**	**Gas (Mcf/d)**	**Oil and NGL (bbl/d)**	**Gas (Mcf/d)**	**Oil and NGL (bbl/d)**
TBNG JV Lands	81.5	6.9	8	5.7	7
Banarli Licenses	100.0	0.7	1	0.7	1
Total		**7.6**	**9**	**6.4**	**8**

Gas sales from the TBNG JV Lands in 2017 averaged 6.9 MMcf/d (gross) or 5.7 MMcf/d (net). Oil and natural gas liquids sales totaled 8 bbl/d (gross) or 7 bbl/d (net). Average realized prices for Valeura's gas sales from the TBNG JV Lands were $7.02/Mcf in 2017. The TBNG JV owns and controls all of its local gas gathering, compression, and export lines to its customers (shown in red on the figure below). This system is currently underutilized and has the capacity to handle approximately 35 MMcf/d. There is also proximal pipeline infrastructure capable of several Bcf/day. These include tie in to the regional gas distributor GAZDAZ, a domestic line to Istanbul, an export line to Greece and the planned TANAP line to Europe. See the diagram below for details of pipeline infrastructure around Valeura's lands the TBNG owned distribution pipelines.

Gas sales from the Banarli Licences in 2017 averaged 0.7 MMcf/d (gross and net). Oil and natural gas liquids sales totaled 1 bbl/d (gross and net). Average realized prices for Valeura's gas sales from the Banarli Licences were $6.67/ Mcf in 2017. Natural gas from Banarli is being sold to the TBNG JV, net of a transportation and marketing fee, and is being distributed to existing TBNG JV customers located north of Banarli. Valeura receives the majority of the benefits from this fee arrangement and the associated proceeds by virtue of its current 81.5% working interest in the TBNG JV facilities.



Operations

Shallow Conventional Gas

Conventional gas is produced from Tertiary-aged stacked sands in the Danismen and Osmancik formations at relatively shallow depths of 500 to 1,500 metres. Valeura has been active in the production and exploration of gas resources in these blocks since 2011. The Company has also been a partner in the development of shallow tight gas resources from the slightly deeper Mezardre, Teslimkoy and Kesan Formations using a combination of vertical and horizontal drilling and fracing.

All of the production on the TBNG JV Lands and Banarli Licenses in 2017 was conventional shallow gas produced from 91 wells (89 wells on the TBNG JV Lands and two on the Banarli Licenses), along with a small amount of oil and NGLs.

In 2017, on the TBNG JV Lands, Valeura completed 35 workovers on existing production wells and also performed re-entry fracing on two wells. The Company also drilled six new shallow gas wells on the TBNG JV Lands and Banarli Licenses. Three of the wells are currently producing, one well was plugged and abandoned as a dry hole and two others are suspended and under evaluation. In addition, 500 square kilometres of additional 3D seismic was acquired over the Banarli Licences and TBNG JV Lands that will contribute conventional shallow gas and BCGA play opportunities.

BCGA Play

Valeura identified the potential for an unconventional play in the Thrace Basin between 2011 and 2013 based on drilling results and regional geological modelling. The Company noted increasing overpressure and gas saturation as wells were drilled deeper and closer to the heart of the basin. Compilation of the data, suggested that the basin could contain a BCGA. A BCGA is an unconventional play where the hydrocarbons are trapped strictly by the poor quality (very low permeability) of the reservoir rocks. As an unconventional play, when discovered, the hydrocarbons can be pervasive across the whole basin, but normally require enhanced production technologies such as horizontal wells and fracing.

Based on the BCGA thesis, the Company acquired the rights to more land in the Thrace Basin BCGA fairway through the award of the Banarli Licenses. In 2015 and 2016, the Company drilled the Hayrabula-10 well and the Yayli-1 well which were deepened and provided more evidence supporting the BCGA play. In 2017, the Company completed the TBNG Acquisition which gave it 81.5% ownership and operating control of the West Thrace Lands. Also in 2017, the Company completed the Banarli Farm-in and the West Thrace Deep Rights Sale with Statoil, which brought Statoil in as a 50% partner in the deep formations and provided financing to explore the BCGA. See "*Development of the Business – Three Year History*".

The Yamalik-1 well was drilled, completed and tested in 2017. The well encountered highly overpressed gas saturated Teslimkoy and Kesan Formations from approximately 2,900 metres down to the total depth of 4,196 metres. The overpressure at the total depth was greater than 0.8 psi/ft based on testing results. There were no sections that were interpreted as water-bearing, or where the pressures dropped. The average net sand in the objective section was approximately 44%. Yamalik-1 supported the BCGA thesis at this location and exceeded the criteria required to proceed with completion and testing.

The Yamalik-1 well testing program was designed to demonstrate that fracing would allow gas to flow to the surface from these deep, tight reservoirs, without the production of significant formation water. Four separate production test were carried out with each producing from two fraced intervals (eight fracs in total). The production testing results exceeded management's expectations. The 24-hour aggregate production test rate of 2.9 MMcf/d from the four production tests in the Kesan Formation was better than modelled. Additionally, the gas was at a higher pressure than expected and the gas flowed with a significant amount of condensate (with a test data range of 20 to 70 barrels per MMcf).

Valeura is now proceeding with engineering and design work to enable Yamalik-1 to be tied into Valeura's gas gathering and sales network. Valeura is targeting to recommence operations in early Q3 2018. The project is expected be funded jointly by Valeura and Statoil.

The Company is currently finalizing with its partner, Statoil, a three well delineation campaign to prove the lateral extend of the BCGA and to drill up to 5000 metres to try and establish the reservoir floor for the play. The first of these three wells will be drilled in Banarli Licenses and will be fully funded by Statoil as its Phase 3 commitment under the Banarli Farm-in.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Reserves in Turkey

The Company engaged D&M to prepare a report relating to the Company's reserves in Turkey as at December 31, 2017. The reserves on the properties described herein are estimates only. Actual reserves on these properties may be greater or less than those estimated.

All of the Company's crude oil and natural gas reserves in Turkey are located in the Thrace Basin. Set out below is a summary of the crude oil and natural gas reserves and the value of future net revenue of the Company as at December 31, 2017 as evaluated by D&M in the D&M Reserves Report. The reserves evaluated by D&M in the D&M Reserves Report are summarized in Appendix A-1. The report on the reserves data by D&M (in Form 51-101F2) and the report of the Company's management and Board on such reserves data (in Form 51-101F3) are included in this Annual Information Form as Appendices A-3 and A-5, respectively.

The following is a summary of the D&M Reserves Report which is qualified in its entirety by the Company's Statement of Reserves Data and Other Oil and Gas Information attached as Appendix A-1 hereto.

Oil and Gas Reserves
Based on Forecast Prices and Costs[1]

	Light and Medium Oil Crude Oil		Heavy Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
	Gross (Mbbl)	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
Proved Developed Producing	5	4	-	-	3,579	3,097	-	-	602	520
Proved Developed Non-Producing			-	-	1,866	1,614	-	-	311	269
Proved Undeveloped			-	-	7,791	6,739	-	-	1,299	1,123
Total Proved	5	4	-	-	13,236	11,450	-	-	2,211	1,912
Total Probable	3	2	-	-	33,611	29,086	-	-	5,605	4,850
Total Proved Plus Probable	8	6	-	-	46,847	40,536	-	-	7,816	6,762
Total Possible	5	4	-	-	26,565	22,998		-	4,433	3,837
Total Proved Plus Probable Plus Possible	13	10	-	-	73,412	63,534	-	-	12,249	10,599

Net Present Values of Future Net Revenue
Based on Forecast Prices and Costs[1][2]

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes[15] Discounted At				
	0% (M US$)	**5% (M US$)**	**10% (M US$)**	**15% (M US$)**	**20% (M US$)**	**0% (M US$)**	**5% (M US$)**	**10% (M US$)**	**15% (M US$)**	**20% (M US$)**
Proved Developed Producing[2][5][6]	4,360	4,384	4,365	4,314	4,239	3,006	3,051	3,154	3,055	3,027
Proved Developed Non-Producing[2][5][7]	5,360	4,456	3,733	3,148	2,670	4,560	3,798	3,177	2,700	2,300
Proved Undeveloped[2][8]	13,299	9,125	6,024	3,719	2,005	10,558	7,168	4,582	2,796	1,416
Total Proved[2]	23,019	17,965	14,122	11,181	8,914	18,124	14,017	10,913	8,551	6,743
Total Probable[3]	88,817	57,661	37,732	24,896	16,578	69,858	44,918	29,130	18,911	12,384
Total Proved Plus Probable[2][3]	111,836	75,626	51,854	36,077	25,492	87,982	58,935	40,043	27,462	29,127
Total Possible[4]	100,913	62,940	40,945	27,825	19,749	81,263	50,617	32,903	22,464	16,026
Total Proved Plus Probable Plus Possible[2][3][4]	212,749	138,566	92,799	63,902	45,241	169,245	109,552	72,946	49,926	35,153

Note:

See Notes that follow the table titled "*Reconciliation of the Company's Gross Reserves by Principal Product Type Based on Forecast Prices and Costs*" in Appendix A-1.

PROSPECTIVE RESOURCES

The prospective resources evaluated by D&M in the D&M Resources Report are summarized in Appendix A-2. The report on the prospective resources data by D&M (in Form 51-101F2) and the report from the Company's management and the Board on such prospective resources data (in Form 51-101F3) are included in this Annual Information form as Appendices A-4 and A-5, respectively.

DESCRIPTION OF CAPITAL STRUCTURE

Valeura is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares (the "**Preferred Shares**").

As at December 31, 2017, there were 73,148,321 Common Shares and nil Preferred Shares outstanding. As of the date hereof, there were 83,675,321 Common Shares outstanding as a result of the 2018 Offering. In addition, as of the date hereof, there were 6,370,500 Options outstanding.

Common Shares

The Company is authorized to issue an unlimited number of Common Shares. The holders of the Common Shares are entitled to dividends, if, as and when declared by the Board, to one vote per share at meetings of the Shareholders and, upon liquidation, to receive such assets of the Company as are distributable to the holders of the Common Shares.

Preferred Shares

The Company is authorized to issue an unlimited number of Preferred Shares, issuable in series. Each series of Preferred Shares will have such designations, rights, privileges, restrictions and conditions as the Board may from time to time determine before issuance. The holders of each series of Preferred Shares will be entitled, in priority to holders of Common Shares, to be paid rateably with holders of each other series of Preferred Shares the amount of dividends, if any, specified as being payable preferentially to the holders of such series and, upon liquidation, dissolution or winding-up of the Company, in priority to holders of Common Shares, to be paid rateably with holders of each other series of Preferred Shares the amount, if any, specified as being payable preferentially to holders of such series.

DIVIDENDS

Valeura has not declared or paid any dividends on the Common Shares since incorporation. It is not currently expected that dividends will be paid in respect of the Common Shares during the current phase of development of Valeura's business and operations. The payment of dividends in the future will be at the discretion of the Board and will be dependent on the future earnings and financial condition of the Company and such other factors as the Board considers appropriate.

PRIOR SALES

Valeura has not issued or sold any securities convertible into Common Shares during the year ended December 31, 2017, except as set forth below.

Date of Issue/Grant	Number and Designation of Securities	Issue/Exercise Price
March 17, 2017	1,000,000 Options	$0.73
May 17, 2017	600,000 Options	$0.75
May 31, 2017	150,000 Options	$0.80

MARKET FOR COMMON SHARES

The Common Shares are listed and posted for trading on the TSX under the symbol VLE. The following table sets forth the price ranges and traded volume of Common Shares in 2017 as reported by the TSX.

Period	High ($)	Low ($)	Volume
January	1.00	0.84	1,242,866
February	0.90	0.83	756,937
March	0.87	0.63	2,095,135
April	0.78	0.63	928,181
May	0.85	0.62	1,036,121
June	0.80	0.65	618,514
July	0.72	0.62	890,432
August	0.71	0.52	1,116,294
September	0.56	0.48	971,417
October	0.70	0.42	2,360,588
November	2.28	0.55	11,531,094
December	5.02	2.08	26,374,153

DIRECTORS AND EXECUTIVE OFFICERS

Directors and Executive Officers

The following table sets forth the names, province or state and country of residence, present positions with Valeura and principal occupations during the past five years of the directors and executive officers of Valeura. The term of office for each director is from the date of the annual meeting at which they are elected until the next annual meeting or until their successor is elected or appointed.

Name and Residence	Position(s) with Valeura	Principal Occupation(s) During the Past Five Years
Dr. Timothy R. Marchant(1)(3) Calgary, Alberta, Canada	Chairman since 2018 Director since 2015	Adjunct Professor of Strategy and Energy Geopolitics, Haskayne School of Business, University of Calgary Director of Vermilion Energy Inc. since 2010. Director of Cub Energy Inc. since 2013.
William T. Fanagan(1)(2) Vancouver, British Columbia, Canada	Director since 2010	Private Businessman since August 2001.
Claudio A. Ghersinich(2)(3) Calgary, Alberta, Canada	Director since 2010	President and Chief Executive Officer of Carrera Investments Corp. since May 2005. Director of Vermilion Energy Inc. from 1994 until 2017. Chairman of the Board, ArPetrol Ltd. from March 2011 to December 2016.
Russell Hiscock(1)(2) Montreal, Quebec, Canada	Director since 2017	President and Chief Executive Officer of the CN Investment Division since 2008.
James D. McFarland Calgary, Alberta, Canada	Director since 2010	President and Chief Executive Officer of Valeura from April 2010 to October 2017 and Chief Executive Officer from October 2017 to December 2017. Director of Pengrowth Energy Corporation and MEG Energy Corp since 2010.
Ronald W. Royal(2)(3) Abbotsford, British Columbia, Canada	Director since 2010	Private Businessman since April 2007. Director of Gran Tierra Energy Inc. since 2015. Director of Caracal Energy Inc. from 2011 to 2014. Director of Oando Energy Resources Inc. from 2015 to 2016.
W. Sean Guest Calgary, Alberta, Canada	President and Chief Executive Officer	President of Valeura since October 2017 and Chief Executive Officer of Valeura since January 2018. Chief Operating Officer of Valeura May 2017 to December

Name and Residence	Position(s) with Valeura	Principal Occupation(s) During the Past Five Years
		2017. Chief Executive Officer of Bukit Energy from February 2014 to May 2017.
Stephen E. Bjornson Calgary, Alberta, Canada	Chief Financial Officer	Chief Financial Officer of Valeura since April, 2010.
Lyle A. Martinson Calgary, Alberta, Canada	Vice President, Operations	Vice President, Operations of Valeura since April, 2010.
Donald W. Shepherd Calgary, Alberta, Canada	Vice President, Engineering	Vice President, Engineering of Valeura since April, 2010.

Notes:

(1) Member of the Governance and Compensation Committee.
(2) Member of the Audit Committee.
(3) Member of the Reserves & Health, Safety and Environment Committee.

As of the date hereof, the directors and executive officers of Valeura, as a group, beneficially own, directly or indirectly, 3,360,755 Common Shares representing approximately 3.8% of the issued and outstanding Common Shares.

As of the date hereof, the directors and executive officers of Valeura, as a group, beneficially own, directly or indirectly 4,568,000 Options. If all such Options were exercised, the directors and executive officers of Valeura, as a group, would hold approximately 8.5% of the then issued and outstanding Common Shares (on a fully diluted basis).

Corporate Cease Trade Orders or Bankruptcies

To the knowledge of management, no director or executive officer of Valeura is, or has been, within the past 10 years before the date hereof, a director or executive officer of any issuer that, while that person was acting in that capacity: (i) was the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under securities legislation for a period of more than 30 consecutive days; or (ii) was subject to an event that resulted, after the person ceased to be a director or executive officer, in the issuer being the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under securities legislation for a period of more than 30 consecutive days.

To the knowledge of management, no director or executive officer of Valeura is, or has been, within the past 10 years before the date hereof, a director or executive officer of any issuer that, while that person was acting in that capacity or within a year of that issuer ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Personal Bankruptcies

To the knowledge of management, no director or executive officer of Valeura has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or became subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold such person's assets.

Penalties or Sanctions

To the knowledge of management, no director or executive officer of Valeura has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, other than penalties for late filing of insider reports; or (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Circumstances may arise where Board members are directors or officers of companies which are in competition to the interests of Valeura. No assurances can be given that opportunities identified by such Board members will be provided to Valeura. Pursuant to the ABCA, directors who have an interest in a proposed transaction upon which the Board is voting are required to disclose their interests and refrain from voting on the transaction.

AUDIT COMMITTEE

Composition of the Audit Committee

The Audit Committee of the Board operates under written terms of reference that set out its responsibilities and composition requirements. A copy of the terms of reference is attached to this Annual Information Form as Appendix B. The Audit Committee consists of Messrs. Hiscock (Chair), Fanagan, Ghersinich and Royal. All members of the Audit Committee are independent and financially literate as such terms are defined by National Instrument 52-110 – *Audit Committees*.

The following sets out the education and experience of each director relevant to the performance of his duties as a member of the Audit Committee. The chair of the Audit Committee, Mr. Russell Hiscock, holds a Chartered Financial Analyst designation as well as a Certified Management Accountant designation and has accounting and financial experience as a result of his role as President and Chief Executive Officer CN Investment Division. Mr. William T. Fanagan holds a Chartered Accountant designation from the Institute of Chartered Accountants in Ireland and has accounting and financial expertise as a result of his experience as the President and Chief Executive Officer of a publicly traded international oil and gas company. Mr. Claudio A. Ghersinich holds a Bachelor of Science degree in Civil Engineering from the University of Manitoba and has obtained financial experience and exposure to accounting and financial issues in a role as a founder of a publicly traded oil and gas company in 1994 and as an audit committee member of other public companies. Mr. Ronald W. Royal holds a Bachelor of Applied Science degree in Mechanical Engineering from the University of British Columbia and has obtained financial experience and exposure to accounting and financial issues through his involvement as an executive officer of international affiliates of ExxonMobil Corporation.

Auditors' Fees

KPMG LLP, Chartered Professional Accountants, became Valeura's auditors on April 9, 2010. Fees paid to Valeura's auditors for the years ended December 31, 2017 and 2016 are detailed below.

Fee	For the year ended December 31, 2017	For the year ended December 31, 2016
Audit Fees(1)	$301,700	$222,200
Tax Fees(2)	-	-
All Other Fees	$36,500	$29,920
Total	$338,200	$252,120

Notes:

(1) "Audit Fees" include the aggregate professional fees paid to the external auditors for the audit of the annual consolidated financial statements and other annual regulatory audits and filings. It also includes the aggregate fees paid to the external auditors for services related to the audit services, including reviewing quarterly financial statements and management's discussion thereon and consulting with the Board and Audit Committee regarding financial reporting and accounting standards.

(2) "Tax Fees" include the aggregate fees paid to external auditors for tax compliance, tax advice, tax planning and advisory services, including preparation of tax returns.

All permissible categories of non-audit services require pre-approval by the Audit Committee, subject to certain statutory exemptions.

RISK FACTORS

Foreign Operations

Valeura currently has all of its operations in Turkey and will likely continue to have all of its operations outside of Canada. Exploration, development and operating activities in Turkey are subject to the risks normally associated with the conduct of business in countries with less developed or emerging economies. As such, the Company's operations, financial condition and operating results could be significantly affected by risks over which it has no control. These risks may include risks related to economic, social or political instability or change, terrorism, hyperinflation, currency non-convertibility or instability and changes of laws affecting foreign ownership, interpretation or renegotiation of existing contracts, government participation, taxation policies, including royalty and tax increases and retroactive tax claims, and investment restrictions, working conditions, rates of exchange, exchange control, exploration licensing, production leasing, petroleum and export licensing and export duties, government control over domestic oil and gas pricing, currency fluctuations, devaluation or other activities that limit or disrupt markets and restrict payments or the movement of funds, the possibility of being subject to exclusive jurisdiction of foreign courts in connection with legal disputes relating to licences to operate and concession rights in countries where Valeura currently operates, and difficulties in enforcing Valeura's rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations. Problems may also arise due to the quality or failure of equipment or technical support, which could result in failure to achieve expected target dates for exploration and development operations or result in a requirement for greater expenditure. Valeura will operate in such a manner as to minimize and mitigate its exposure to these risks. However, there can be no assurance that Valeura will be successful in protecting itself from the impact of all of these risks and the related financial consequences.

Acts of Violence, Terrorist Attacks or Civil Unrest in Turkey

During the 2014 to 2016 period, Turkey experienced increased periods of political unrest and civil disobedience primarily associated with the Syrian civil war on its border, the large influx of Syrian refugees to Turkey, the movement of Kurdish fighters from Turkey into Syria and the end of a truce in mid-2015 between the PKK and the Turkish government. More recently, suicide bomb attacks in Ankara and Istanbul have increased security concerns in Turkey. Also, the shooting down by the Turkish military of a Russian jet fighter in November 2015 engaged in the Syrian civil war and purported to have entered Turkish air space has increased tensions between Russia and Turkey and its NATO allies. In July 2016, Turkey experienced an attempted military coup, which quickly failed. In the aftermath of the coup, the military perpetrators were arrested as well as thousands of other citizens suspected of being followers of the exiled Muslim cleric Fethullah Gulen. These events have resulted in a further devaluation of the TL, which has negatively impacted the Company's natural gas revenues from the country (revenues denominated in TL).

On April 16, 2017, Turkey held a referendum on a proposed new constitution which was endorsed by a narrow margin. The result served to stabilize the TL value against the Canadian Dollar for period of time. However, further developments in 2017, including the detention of a U.S. embassy worker, have again destabilized the value of the TL. The Company will continue to monitor conditions, including the safety of personnel and operations, the security situation generally, impact on the TL and banking facilities, impact on our joint venture partners and any changes in offtakes by the Company's natural gas customers.

To date, the above events have not impacted the Company's ability to conduct operated and non-operated drilling and production operations in the Thrace Basin and no significant delays or security issues have been experienced in these operations. All of the Company's current operated and non-operated operations are in the Thrace Basin of northwest Turkey, more than 1,000 kilometres from the Syrian border.

In the future, access to some operating locations in Turkey may be precluded and Valeura may incur substantial costs to maintain the safety of personnel and operations. Despite these precautions, the safety of operator personnel or Valeura personnel in these locations may be at risk, and Valeura may in the future suffer loss of personnel and disruption of operations, any of which could have a material adverse effect on Valeura's business and results of operations.

Variations in Foreign Exchange Rates and Interest Rates

The Company's drilling operations in Turkey and related contracts are based in U.S. Dollars. Material increases in the value of the U.S. Dollar will negatively impact the Company's costs of drilling and completions activity. Future Canadian Dollar/U.S. Dollar and Canadian Dollar/TL exchange rates could impact the future value of the Company's reserves as determined by independent evaluators. The Company's functional currency in its subsidiary operations in Turkey is TL. The revenue stream in Turkey is based on TL revenue for natural gas and U.S. Dollar based revenue for crude oil translated into TL. The majority of costs will be incurred in U.S. Dollars for capital expenditures and TL for operating expenditures. Decreases in the value of the TL could result in decreases in revenue. Increases in the value of the TL and U.S. Dollar could result in increases in the cost of operations. To the extent that the Company engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Company may contract. Valeura continues to assess its exposure to all foreign currencies. Recent volatility and weakness in the value of the TL may impair the ability of the Company to manage this exposure. Further devaluation of the TL without a corresponding increase in the natural gas reference price will result in continued decreases in funds flow from operations and will affect the ability of the Company to meet its financial obligations.

Estimates of Resources

The resources estimates presented in the D&M Resources Report have been classified as prospective resources. The resources estimates in the D&M Resources Report are estimates only. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. Readers are cautioned that the quantities presented are estimates only and should not be construed as being exact quantities.

Price Volatility, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by Valeura will be affected by numerous factors beyond its control. Valeura's ability to market its natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. Valeura may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities, and related to operational problems with such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Valeura's revenues, profitability, future growth and the carrying value of its oil and gas properties, provided such properties yield production, are substantially dependent on prevailing prices of oil and gas. Valeura's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of Valeura. These factors include economic conditions in the United States, Canada, and Turkey, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, and political instability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports and the availability of alternative fuel sources. In Turkey, natural gas prices for domestic sales are effectively set by the government, which are indirectly affected by these market forces. Any substantial and extended decline in the price of oil and gas would have an adverse effect on Valeura's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. The exchange rate between the Canadian Dollar, U.S. Dollar and TL also affects the profitability of Valeura. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value.

Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects. Currently, the Company has no debt facilities in place. However, any bank borrowings available to Valeura in the future will in part be determined by Valeura's borrowing base. A sustained material decline in prices from historical average prices could reduce Valeura's borrowing base, therefore reducing the bank credit available to the Company and require that a portion, or all, of Valeura's bank debt, if any, be repaid.

Government Rules and Regulations

Valeura's operations are subject to various levels of government controls and regulations in the countries where it operates. Oil and gas exploration and production is a sensitive political issue and as a result there is a relatively higher risk of direct government intervention in respect of laws and regulations that can affect the property rights and title to Valeura's assets in Turkey. Such intervention can extend, in certain jurisdictions, to nationalization, expropriation or other actions that effectively deprive companies of their assets.

Existing laws and regulations include matters relating to land tenure, drilling, production practices including hydraulic fracturing of wells, environmental protection, agricultural land use, marketing and pricing policies, royalties, various taxes and levies including income tax, foreign trade and investment and government approval of lease and licence transfers and other regulatory approvals that are subject to change from time to time. Current legislation is generally a matter of public record and Valeura cannot predict what additional legislation or amendments may be proposed that will affect Valeura's operations or when any such proposals, if enacted, might become effective. There is no certainty regarding obtaining government approvals. Changes in government policy or laws and regulations could adversely affect Valeura's results of operations and financial condition. In particular, a number of changes in the land tenure regulations associated with the New Petroleum Law are in the early years of implementation and the full effect of these changes remain uncertain. Failure to comply with applicable laws, regulations and legal requirements may result in enforcement actions thereunder, including orders issued by regulatory or judicial authorities causing operations to cease or be curtailed and may include corrective measures requiring capital expenditures, installation of additional equipment or remedial actions which could have an adverse effect on Valeura's business, financial condition or operations.

Management of Key Relationships in Turkey

Failure to manage relationships with local communities, government and non-government organizations could adversely impact Valeura's business in Turkey. Negative community reaction to operations could have an adverse impact on profitability, the ability to finance or even the viability of Valeura in Turkey. This reaction could lead to disputes that may damage the Company's reputation and could lead to potential disruption of projects or operations.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Valeura will depend on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves Valeura may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Valeura's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. No assurance can be given that Valeura will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, Valeura may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Valeura.

While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, natural declines as reserves are depleted and production or sales delays cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, Valeura will not be fully insured against all of these risks, nor are all such risks insurable. Although Valeura will maintain liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Valeura could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. In particular, formation pressures have been shown to be elevated below approximately 2,500 metres on the Banarli Licences and West Thrace Lands requiring specialized equipment in drilling and completion operations. There is uncertainty regarding the sustainability of initial production rates and decline rates thereafter, and management believes that new shallow gas wells and new fraced tight gas wells will exhibit relatively high decline rates at 50% and 75%, or more, respectively, in their first year of production. There are also risks and uncertainty regarding the Company's ability to address technical drilling challenges and manage water production. Losses resulting from the occurrence of any of these risks could have a material adverse effect on future results of operations, liquidity and financial condition.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of regulations in foreign jurisdictions where Valeura operates. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. Currently, there are no restrictions on the hydraulic fracturing of wells in Turkey. However a number of jurisdictions in Europe have temporarily or permanently banned hydraulic fracturing of wells and there is a risk that these restrictions may spread to other jurisdictions in the region including Turkey. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Valeura to incur costs to remedy such discharge. Although Valeura believes it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws or agricultural land use requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Valeura's financial condition, results of operations or prospects.

Substantial Capital Requirements

Valeura anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If its revenues or reserves decline, it may have limited ability to acquire or expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Valeura. The potential inability of Valeura to access sufficient capital for its operations could have a material adverse effect on Valeura's financial condition, results of operations or prospects.

The Company's capital expenditures include expenditures in oil and gas activities which may or may not be successful. The Company makes adjustments to the capital structure in light of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. In order to maintain or adjust the capital structure, the Company may, from time to time, issue shares, adjust its capital spending or issue debt instruments. The Company is not subject to any externally imposed capital requirements while it maintains operatorship over all the lands in the Thrace Basin, with the exception that Statoil may, in 2019, elect to complete Phase 3 under the Banarli Farm-in and thereby earn a 50% working interest in the deep rights in the Banarli Licences. At that point, Statoil may exercise its option under the Banarli Farm-in to take operatorship of the deep rights and propose a more significant drilling program. Under the 2018 Offering, the Company raised approximately $56 million in net proceeds in order to meet commitments for an expended capital program; however, such a program could result in an even more significant capital commitment for which the Company will be required to further assess alternatives including the availability of equity and debt capital to fund the program.

Additional Funding Requirements

Valeura's cash flow from its reserves, once developed, may not be sufficient to fund its ongoing activities at all times. From time to time, Valeura may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause Valeura to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Valeura's revenues from its reserves, once developed, decrease as a result of lower oil and natural gas prices or otherwise, it will affect Valeura's ability to expend the necessary capital to replace its reserves or to maintain its production. If cash flow from operations is not sufficient for Valeura to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable to Valeura.

Issuance of Debt

From time to time Valeura may enter into transactions to acquire assets or the shares of other entities. Valeura may have difficulty accessing debt needed to acquire and develop international oil and gas properties. This may result in the inability of Valeura to complete certain acquisitions or drilling activities. Future acquisitions may be financed partially or wholly with debt, which may increase debt levels above industry standards. Depending on future exploration and development plans, Valeura may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither Valeura's articles nor its by-laws limit the amount of indebtedness that it may incur. The level of Valeura's indebtedness from time to time could impair its ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time Valeura may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Valeura will not benefit from such increases and may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Given that Valeura's natural gas sales and revenues in Turkey are priced in TL, Valeura from time to time may enter into agreements to fix the exchange rate of Canadian or United States Dollars to the TL in order to offset the risk of revenue losses. Valeura may similarly seek to fix the exchange rate between the TL and the Canadian or U.S. Dollar to offset the risk of a relative strengthening of the U.S. Dollar, which is the currency basis for large portion of the capital expenditures in Turkey.

Availability of Drilling, Hydraulic Fracturing and Other Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling, hydraulic fracturing and other related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Valeura and may delay exploration and development activities. To the extent it is not the operator of its oil and gas properties, Valeura will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Title to Assets

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. While it is the practice of Valeura, in acquiring significant oil and gas leases or interest in oil and gas leases to fully examine the title to the interest under the lease, this should not be construed as a guarantee of title. There may be title defects that affect lands comprising a portion of Valeura's properties. To the extent title defects do exist, it is possible that Valeura may lose all or a portion of its right, title, estate and interest in and to the properties to which the title relates.

Competition

Oil and gas exploration is intensely competitive in all its phases and involves a high degree of uncertainty with respect to the impact of such competition. Valeura will compete with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of Valeura. Valeura's ability to increase reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire suitable producing properties or acquire new exploration licences. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Valeura may also be subject to competition from the alternative fuel industry or fuel substitution by its customers.

Reserves Are Estimates Only

There are numerous uncertainties inherent in estimating quantities of proved, probable and possible reserves and future net revenue to be derived therefrom, including many factors beyond the control of Valeura. The reserves and future net revenue information set forth herein represents estimates only.

The reserves and estimated future net revenue from Valeura's properties have been independently evaluated by D&M and are contained in the D&M Reserves Report. The D&M Reserves Report includes a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of crude oil, natural gas liquids and natural gas, operating costs, abandonment and salvage values, royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on the respective price forecasts in use at the effective date of the D&M Reserves Report and many of these assumptions are subject to change and are beyond the control of Valeura. Actual production and future net revenue derived therefrom will vary from these evaluations, and such variations could be material. The present value of estimated future net revenue referred to herein should not be construed as the current market value of estimated crude oil, natural gas liquids and natural gas reserves attributable to Valeura's properties. The estimated discounted future net revenue from reserves are based upon price and cost estimates which may vary from actual prices and costs and such variance could be material. Actual future net revenue will also be affected by factors such as the amount and timing of actual production, supply and demand for crude oil and natural gas, curtailments or increases in consumption by purchasers and changes in governmental regulations or taxation.

Depletion of Reserves and Production Declines

Valeura's oil and natural gas reserves and production, and therefore its cash flows and earnings, will be highly dependent upon Valeura developing and increasing its current reserve base and discovering or acquiring additional reserves. Without the addition of reserves through exploration and development activities or acquisition, Valeura's reserves and production will naturally decline over time as reserves are depleted. To the extent that cash flow from operations is insufficient and external sources of capital become limited or unavailable, Valeura's ability to make the necessary capital investments to maintain and expand its oil and natural gas reserves will be impaired. There can be no assurance that Valeura will be able to find and develop or acquire additional reserves to replace production at commercially feasible costs, or that Valeura will be able to convert its contingent resources to reserves.

Insurance

Valeura's involvement in the exploration for and development of oil and natural gas properties may result in it becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although Valeura carries insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not in all circumstances be insurable or, in certain circumstances, Valeura may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to Valeura. The occurrence of a significant event that Valeura is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Valeura's financial position, results of operations or prospects.

Management of Growth

Valeura may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of Valeura to manage growth effectively, including the increasingly complex operations with Statoil, and other acquired assets or companies, will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The potential inability of Valeura to deal with this growth could have a material adverse impact on its business, operations and prospects.

Expiration of Permits, Licences and Leases

Valeura's properties will be held in the form of permits, licences and leases and working interests in permits, licences and leases. If Valeura or the holder of the permit, licence or lease fails to meet the specific requirement of a permit, licence or lease, the permit, licence or lease may terminate or expire (excluding those which may be voluntarily relinquished by the Company). While Valeura monitors the status and expiry of all of its current licences and leases, all of which are in Turkey, there can be no assurance that any of the obligations required to maintain such licences or leases will be met. The termination or expiration of any of its licences or leases or the working interests relating to a licence or lease may have a material adverse effect on Valeura's results of operations and business. To the extent such permits, licences and leases are subsequently suspended or revoked, Valeura may be curtailed or prohibited from proceeding with planned exploration, development or operation of its projects. Failure to comply with permitting and legal requirements may result in enforcement actions, including orders issued by regulatory or judicial authorities causing operations to cease or be curtailed and may include corrective measures requiring capital expenditures, installation of additional equipment or remedial actions which could have an adverse effect on Valeura's business, financial condition or operations.

Internal Controls Over Financial Reporting

Valeura has established internal controls over financial reporting ("**ICFR**") which include policies and procedures that pertain to the maintenance of financial records, the preparation of accurate financial statements, controls over bank accounts and the prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets or funds. Valeura has delegation of authority policies approved by the respective boards of directors of the parent company and each subsidiary, which policies delineate how various corporate and financial matters must be approved and the authority levels of management and employees (including in-country managers in Turkey). Valeura has the right and periodically conducts audits of the records and expenditures of its operating partners. While management has determined that Valeura maintains effective ICFR, Valeura cannot be certain errors or failures will not occur related to financial processes and reporting. Failure to properly implement existing controls, or difficulties encountered in their implementation, could impact the Company's results of operations or cause it to fail to meet its reporting obligations. If the Company or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Company's financial statements and reduce the trading price of the Common Shares.

At the operational level in Turkey, the Company relies upon certain local managers and employees and its operating partners. A large portion of the business and contracts in Turkey are in the Turkish language and the Company must rely on certain key personnel in-country who work in the Turkish language and report to management. A major disruption in the flow of information, or obtaining inaccurate information from these local employees and partners, could adversely impact the accuracy of financial reporting and management information.

Internal Controls and Procedures Over Anti-Corruption Requirements

Valeura has established a Code of Business Conduct and Ethics which includes policies and procedures covering anti-bribery and anti-corruption of foreign public officials, including regular reporting to management and the

Board. While management believes these policies are adequate, and despite careful establishment and implementation, there can be no assurance that these or other anti-bribery or anti-corruption policies and procedures are or will be sufficient to protect against corrupt activity. In particular, Valeura, in spite of its best efforts, may not always be able to prevent or detect corrupt practices by employees, or third parties, such as sub-contractors or its operating partners, which may result in reputational damage, civil and/or criminal liability being imposed on Valeura, which could have an adverse effect on Valeura's business, financial condition or operations.

Seasonality

The level of activity in the oil and gas industry is influenced by seasonal weather patterns. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in demand for the goods and services of Valeura. In Turkey, the wet weather in the winter months of the year can require delays in operations.

Counterparty Risk

Valeura may be exposed to counterparty risk through its contractual arrangements with current or future joint venture partners, farm-in partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations, such failures could have a material adverse effect on Valeura and its cash flow from operations.

Conflicts of Interest

The directors or officers of Valeura may also be directors or officers of other oil and gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with Valeura. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a company who is a party to, or is a director or an officer of, or has some material interest in any person who is a party to, a material contract or proposed material contract with Valeura to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

Specialized Skill and Knowledge

International exploration and development activities such as those the Company is engaged in require specialized skills and knowledge in the areas of petroleum engineering, geology, geophysics and drilling. In addition, specific knowledge and expertise relating to local laws (including regulations relating to land tenure, exploration, development, production, marketing, transportation, the environment, royalties and taxation) and market conditions is required to compete with other international oil and gas entities.

Reliance on Key Personnel

The success of Valeura will depend in large measure on certain key personnel and management. The Company also relies on certain key personnel in-country with the ability to work in the Turkish language and report to management in Canada. The loss of the services of such key personnel could have a material adverse effect on Valeura. Valeura does not have key person insurance in effect for members of management. The competition for qualified personnel in the oil and natural gas industry, particularly the international oil and gas industry in which Valeura operates, can be intense and there can be no assurance that Valeura will be able to attract and retain all personnel necessary for the development and operation of its business.

Shareholders must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of Valeura.

Transportation Costs

Disruption in or increased costs of transportation services could make oil and natural gas a less competitive source of energy or could make Valeura's oil and natural gas less competitive than other sources. The industry depends on pipeline facilities, rail, trucking, ocean-going vessels and barge transportation to deliver shipments, and transportation costs are a significant component of the total cost of supplying oil and natural gas. Disruptions of these transportation services because of weather related problems, strikes, lockouts, terrorist activities, delays or other events could temporarily impair the ability to supply oil and natural gas to customers and may result in lost sales. In addition, increases in transportation costs, or changes in transportation costs for oil and natural gas produced by competitors, could adversely affect profitability. To the extent such increases are sustained, Valeura could experience losses and may decide to discontinue certain operations forcing Valeura to incur closure and/or care and maintenance costs, as the case may be. Additionally, lack of access to transportation may hinder the expansion of production at some of Valeura's properties and Valeura may be required to use more expensive transportation alternatives.

Disruptions in Production

Other factors affecting the production and sale of oil and natural gas that could result in decreases in profitability include: (i) expiration or termination of permits, licences or leases, or sales price redeterminations or suspension of deliveries; (ii) future litigation; (iii) the timing and amount of insurance recoveries; (iv) work stoppages or other labour difficulties; (v) worker vacation schedules and related maintenance activities; and (vi) changes in the market and general economic conditions. Weather conditions, equipment replacement or repair, fires, amounts of rock and other natural materials and other geological conditions can have a significant impact on operating results.

Reliance on Industry Partners

To the extent Valeura is not the operator of its oil and gas properties, Valeura will be dependent on such operators for the timing of activities related to such properties, subject to any influence Valeura can bring to bear in operating committee and technical committee meetings under joint venture agreements or other regular communications, and will largely be unable to direct or control the activities of the operators. The ability of Valeura management to influence other operators, as necessary, to protect its interests will be an important determinant of success. By virtue of the TBNG Acquisition in early 2017, Valeura has taken over the operatorship of the TBNG JV which has significantly increased the Company's level of control of its business in Turkey.

Under the Banarli Farm-in, Statoil has the option to earn a 50% interest in the deep formations on the Banarli Licenses by investing in a capital program. Valeura is operator of the deep exploration program during the earning phase of the Banarli Farm-in. Once Statoil has fully earned its 50% interest, Statoil has the option to request operatorship of the deep program.

Dilution

Valeura may make future acquisitions or enter into financings or other transactions involving the issuance of securities of Valeura which may be dilutive.

Income Taxes

Valeura has filed, and will file, all required income tax returns. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of Valeura, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

INDUSTRY CONDITIONS

Turkey

The oil and natural gas industry in Turkey is subject to controls and regulations governing its operations imposed by legislation enacted by the Turkish governments and with respect to pricing and taxation of oil and natural gas by agreements, all of which should be carefully considered by investors in the oil and gas industry. The Company's activities are affected in varying degrees by government regulations relating to the oil and gas industry and foreign investment. Operations may be affected in varying degrees by government regulations with respect to price controls, export controls, income taxes, value-added taxes, expropriation of property, production restrictions and environmental legislation. It is not expected that any of these controls or regulations will affect the Company's operations in a manner materially different than they would affect other oil and gas companies of similar size operating in Turkey. Outlined below are some of the principal aspects of the legislation, regulations and agreements governing the oil and gas industry in Turkey.

After extensive review and significant input from industry, the Turkish government adopted the New Petroleum Law to replace the Old Petroleum Law on June 30, 2013. The most significant changes as described below relate to land tenure regulations.

Commercial Terms

Turkey's fiscal regime for oil and gas operations is presently comprised of royalties and income tax. Royalties are at 12.5% and the corporate income tax rate is 20%. Under the New Petroleum Law, the government royalty rate remained unchanged at 12.5%. Also, there are no changes in taxation regulations with respect to the petroleum industry.

A 15% withholding tax is applied on dividends to be distributed to foreign entities. However, the withholding tax may be reduced to 10% depending on the bilateral treaties signed between Turkey and the home country of the petroleum rights holder in Turkey.

Land Tenure Regime - Old Petroleum Law

All of the Company's licences and leases in Turkey are regulated under the New Petroleum Law. The regulator imposed a change to mapping coordinates country wide and the result for the Company was a commencement date for the licences as June 27, 2015. A number of pre-existing exploration licences were converted to production leases during a period from November 2012 to December 2015. Three pre-existing production leases remained intact.

Land Tenure Regime - Existing Petroleum Law

The GDPA adopted a new international grid system associated with the New Petroleum Law, in part to facilitate any exploration and development of unconventional resources. Exploration licence awards require the posting of a bond of up to 2% of the work program for the initial term or any subsequent extensions The initial term of new licences will be five years. Exploration licences can be extended up to 11 years (two, two-year extensions plus a two-year discovery extension) prior to carving-out one or more production leases and relinquishing other land, provided a discovery is made by the end of the ninth year.

Some uncertainty remains in the tenure of production leases. The recent practice of the GDPA in awarding new leases over the 2011 to 2016 period to the Company and its partners in the Thrace Basin was to set the initial term for varying periods ranging from five years to 14 years, depending on the expected reserve life, amongst other factors, potentially extendable up to 40 years if the expected reserve life supports such an extension. Note that a few leases were back dated to November 2012 when the previous licence had expired. Also noteworthy, the 2-year discovery extension is applied to the initial production lease and thus the initial lease term commences on the date of the 2-year discovery extension. Although initial term for unconventional production lease applications remains uncertain, it is expected that an initial term would garner a maximum of 20 years with the possibility for two subsequent extensions of 10 years each. The maximum area that may be awarded as a production lease would be one map sheet, or 4 quadrants under the grid system.

Environmental

The oil and natural gas industry is subject to extensive and varying environmental regulations in each of the jurisdictions in which the Company operates. Environmental regulations establish standards respecting health, safety and environmental matters and place restrictions and prohibitions on emissions of oil and natural gas and various substances produced concurrently with oil and natural gas. These regulations can have an impact on the selection of drilling locations and facilities, potentially resulting in increased capital expenditures. In addition, environmental legislation may require those wells and production facilities to be abandoned and sites reclaimed to the satisfaction of local authorities. Valeura is committed to complying with environmental and operation legislation wherever the Company operates.

Pipeline Infrastructure

Valeura through its interests in the TBNG JV has 81.5% ownership and operates its own gas gathering grid and export lines to its 55 customers regional customers. The TBNG JV network is not currently connected to the national gas grid.

BOTAS owns and operates the national crude oil pipeline grid and the national natural gas pipeline grid in Turkey.

With regard to major natural gas pipelines, BOTAS owns and operates the national gas grid which connects essentially all the major population centres and is within easy access to the Company's existing and planned operations in the Thrace Basin of northwest Turkey. At the end of 2010, the BOTAS natural gas pipeline network consisted of 11,593 kilometres of various pipelines sizes from 10-inch to 48-inch diameter.

With regard to major crude oil pipelines, BOTAS owns and operates the following infrastructure: the 18-inch Batman to Dortyol crude oil pipeline, which services the prevalent crude oil producing areas of the southeast Anatolia region; the 24-inch Ceyhan to Kirikkale crude oil pipeline, which supplies mainly imported crude oil to the Kirikkale refinery east of Ankara; and the Turkey portion of the twin 40-inch and 46-inch Kirkuk to Ceyhan oil pipeline delivering Iraqi crude oil to the port city of Ceyhan for export. It also operates the Turkish portion of the Baku to Tbilisi to Ceyhan crude oil pipeline delivering Azeri crude oil to Ceyhan for export.

Pricing and Marketing

Turkey imports more than 99% of its natural gas and 92% of its crude oil energy needs and as such any new domestic production has a ready market. Consequently, the Company does not foresee any major concern with the marketing of crude oil or natural gas from its operations.

Crude oil pricing in Turkey is determined under the Petroleum Market Law No. 5015 (Gazetted on December 12, 2003). The pricing for the sales of crude oil is established according to the nearest accessible global free market condition. The domestic crude oil price is linked to world market factors with the base market price being the price at the nearest delivery port. Customary transportation and crude oil quality premiums or deductions, as the case may be, are applied to determine the crude oil price at the custody transfer point. Domestic purchasers and refiners are to give priority to domestic crude oil under the above pricing process.

Total natural gas consumption in Turkey in 2017 increased almost 20% to approximately 5.5 Bcf/d. BOTAS is the major importer and distributor of natural gas in Turkey. Although some import contracts have been released to private operators, BOTAS currently controls approximately 80% of Turkey's natural gas imports. Given the very small domestic production of approximately 0.04 Bcf/d, there is a robust market for additional domestic natural gas production. Due to the dominance of BOTAS in the natural gas market in Turkey, the BOTAS pricing structure effectively sets the domestic market price. In 2016, Russia supplied approximately 53% of Turkey's natural gas imports followed by Iran at 17%, Azerbaijan at 14%, LNG from Algeria and Nigeria at 12% and spot and other at 5%. Accordingly the BOTAS cost tracks world reference pricing and in turn indirectly influences the price available to domestic producers, translated into TL, at some discount. BOTAS regularly posts prices in TL and its Level-2 wholesale tariff ("**BOTAS Reference Price**") was reduced by 10% effective October 1, 2016 to 0.704145 TL/m^3 and remained at that level for the rest of 2016 and all of 2017. On January 1, 2018, the BOTAS Reference Price was increased by approximately 14% to 0.8TL per cubic metre or approximately CAD$7.50 at the current exchange rate of 3.0TL/CAD$. BOTAS along with a number of other privately owned natural gas distributors in Turkey are expected to be the main potential purchasers of any new domestic natural gas production. The Company expects the BOTAS Reference Price to continue to be indirectly linked to the weighted average cost of imported gas to Turkey and government policy with respect to the level of consumer subsidies, if any.

The Company expects natural gas pricing under its current and future contracts to continue to be at some negotiated discount to the BOTAS Reference Price (0% to 15% discount, dependent on reserve size, the magnitude of daily gas volume deliverable and the nature of the contract). The Company's natural gas production from the TBNG JV Lands are purchased by more than 55 local customers directly tied in to the Company's sales gas distribution system at an average discount as of the date hereof of approximately 2% to the BOTAS Reference Price. The Company's natural gas production from the Banarli Licences is currently tied-in to the TBNG JV facilities and is being purchased by the TBNG JV, net of a transportation and marketing fee (of which Valeura receives 81.5% as a partner in the TBNG JV), resulting in a net discount of approximately 4% from the BOTAS Reference Price.

LEGAL AND REGULATORY PROCEEDINGS

Valeura is not a party to any legal proceeding nor was it a party to, nor is or was any of its property the subject of, any legal proceeding during the year ended December 31, 2017, nor is Valeura aware of any such contemplated legal proceedings, which involve a claim for damages, exclusive of interest and costs, that may exceed 10 percent of the current assets of Valeura.

During the year ended December 31, 2017, there were no: (i) penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority; (ii) penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements the Company entered into before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, officer or principal Shareholder, nor any affiliate or associate of such a person, has or has had any material interest in any transaction or any proposed transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect Valeura.

TRANSFER AGENT AND REGISTRAR

Computershare Trust Company of Canada, at its principal office in Calgary, Alberta, is the transfer agent and registrar for the Common Shares.

MATERIAL CONTRACTS

The Company entered into the following material contracts within the most recently completed financial year:

- the Subsequent Deep Rights Sale Agreement; and
- the underwriting agreement dated February 8, 2018 among the Company, GMP Securities L.P. and Cormark Securities Inc. in respect of the 2018 Offering.

See "*General Development of the Business*".

INTERESTS OF EXPERTS

Reserve and resource estimates contained in this Annual Information Form have been prepared by D&M. As at December 31, 2017, the effective date of those estimates, and as of the date hereof, the principals, directors, officers and associates of D&M, as a group, owned, directly or indirectly, less than one percent of the outstanding Common Shares.

The auditors of the Company, KPMG LLP, are independent with respect to the Company, in accordance with the Rules of Professional Conduct of the Institute of Chartered Professional Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans is contained in the Proxy Statement and Information Circular of the Company prepared in connection with the most recent annual meeting of Shareholders that involved the election of directors. Additional financial information is provided in the Company's financial statements and management discussion and analysis for the year ended December 31, 2017.

Copies of this Annual Information Form, any interim financial statements of the Company subsequent to the annual financial statements, the Company's Proxy Statement and Information Circular and other additional information relating to the Company are available on SEDAR at www.sedar.com.

APPENDIX A-1 – FORM 51-101F1 – STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

FORM 51-101F1 STATEMENT OF RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

(Capitalized terms not specifically defined in this Appendix A-1 have the meaning ascribed to them in the Annual Information Form to which this Appendix A-1 is attached)

The Company engaged D&M to prepare a report relating to the Company's reserves in Turkey as at December 31, 2017. The reserves on the properties in Turkey described herein are estimates only. Actual reserves on these properties may be greater or less than those estimated.

The Company's crude oil and natural gas reserves in Turkey are located in the Thrace Basin. Set out below is a summary of the crude oil and natural gas reserves and the value of future net revenue of the Company as at December 31, 2017 as evaluated by D&M the D&M Reserves Report.

The D&M Reserves Report was prepared using assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with NI 51-101.

The estimated future net revenues contained in the following tables do not necessarily represent the fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the D&M Reserves Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the D&M Reserves Report.

OIL AND GAS RESERVES BASED ON FORECAST PRICES AND COSTS(9)

	Light and Medium Crude Oil		Heavy Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Total Oil Equivalent(10)	
	Gross(1) (Mbbl)	Net(1) (Mbbl)	Gross(1) (Mbbl)	Net(1) (Mbbl)	Gross(1) (MMcf)	Net(1) (MMcf)	Gross(1) (Mbbl)	Net(1) (Mbbl)	Gross(1) (Mboe)	Net(1) (Mboe)
Proved Developed Producing(2)(5)(6)	5	4	-	-	3,579	3,097	-	-	602	520
Proved Developed Non-Producing(2)(5)(7)	-	-	-	-	1,866	1,614	-	-	311	269
Proved Undeveloped(2)(8)	-	-	-	-	7,791	6,739	-	-	1,298	1,123
Total Proved(2)	5	4	-	-	13,236	11,450	-	-	2,211	1,912
Total Probable(3)	3	2	-	-	33,611	29,086	-	-	5,605	4,850
Total Proved Plus Probable(2)(3)	8	6	-	-	46,847	40,536	-	-	7,816	6,762
Total Possible(4)	5	4	-	-	26,565	22,998	-	-	4,433	3,837
Total Proved Plus Probable Plus Possible(2)(3)(4)	13	10	-	-	73,412	63,534	-	-	12,249	10,599

NET PRESENT VALUES OF FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS(9)(15)

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes(15) Discounted At				
	0% (M US$)	5% (M US$)	10% (M US$)	15% (M US$)	20% (M US$)	0% (M US$)	5% (M US$)	10% (M US$)	15% (M US$)	20% (M US$)
Proved Developed Producing(2)(5)(6)	4,360	4,384	4,365	4,314	4,239	3,006	3,051	3,154	3,055	3,027
Proved Developed Non-Producing(2)(5)(7)	5,360	4,456	3,733	3,148	2,670	4,560	3,798	3,177	2,700	2,300

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes[15] Discounted At				
	0% (M US$)	**5% (M US$)**	**10% (M US$)**	**15% (M US$)**	**20% (M US$)**	**0% (M US$)**	**5% (M US$)**	**10% (M US$)**	**15% (M US$)**	**20% (M US$)**
Proved Undeveloped[(2)(8)]	13,299	9,125	6,024	3,719	2,005	10,558	7,168	4,582	2,796	1,416
Total Proved[(2)]	23,019	17,965	14,122	11,181	8,914	18,124	14,017	10,913	8,551	6,743
Total Probable[(3)]	88,817	57,661	37,732	24,896	16,578	69,858	44,918	29,130	18,911	12,384
Total Proved Plus Probable[(2)(3)]	111,836	75,626	51,854	36,077	25,492	87,982	58,935	40,043	27,462	29,127
Total Possible[(4)]	100,913	62,940	40,945	27,825	19,749	81,263	50,617	32,903	22,464	16,026
Total Proved Plus Probable Plus Possible[(2)(3)(4)]	212,749	138,566	92,799	63,902	45,241	169,245	109,552	72,946	49,926	35,153

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) BASED ON FORECAST PRICES AND COSTS[(9)]

	Revenue (M US$)	Royalties (M US$)	Operating Costs (M US$)	Development Costs (M US$)	Abandonment and Reclamation Costs (M US$)	Future Net Revenue Before Income Taxes (M US$)	Income Taxes[(15)] (M US$)	Future Net Revenue After Income Taxes[(15)] (M US$)
Total Proved[(2)]	85,471	11,532	15,422	27,087	8,411	23,019	4,895	18,124
Total Proved Plus Probable[(2)(3)]	323,198	43,549	42,354	114,688	10,771	111,836	23,854	87,982
Total Proved Plus Probable Plus Possible[(2)(3)(4)]	521,519	70,206	68,422	157,812	12,330	212,749	43,504	169,245

FUTURE NET REVENUE BY PRODUCT TYPE
BASED ON FORECAST PRICES AND COSTS[9]

	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M US$)	US$/boe[10]	US$/Mcfe[11]
Total Proved[2]	Light and medium crude oil[12]	-	-	-
	Heavy crude oil[12]	-	-	-
	Conventional natural gas[13][16]	14,123	7.39	1.23
Total Proved[2]		**14,123**	**7.39**	**1.23**
Probable[3]	Light and medium crude oil[12]	-	-	-
	Heavy crude oil[12]	-	-	-
	Conventional natural gas[13][16]	37,732	7.78	1.30
Total Probable[3]		**37,732**	**7.78**	**1.30**
Total Proved Plus Probable[2][3]	Light and medium crude oil[12]	-	-	-
	Heavy crude oil[12]	-	-	-
	Conventional natural gas[13][16]	51,855	7.67	1.28
Total Proved Plus Probable[2][3]		**51,855**	**7.67**	**1.28**
Possible[4]	Light and medium crude oil[12]	-	-	-
	Heavy crude oil[12]	-	-	-
	Conventional natural gas[13][16]	40,945	10.67	1.78
Total Possible[4]		**40,945**	**10.67**	**1.78**
Total Proved Plus Probable Plus Possible[2][3][4]	Light and medium crude oil[12]	-	-	-
	Heavy crude oil[12]	-	-	-
	Conventional natural gas[13][16]	92,800	8.76	1.46
Total Proved Plus Probable Plus Possible[2][3][4]		**92,800**	**8.76**	**1.46**

The pricing assumptions used in the D&M Reserves Report with respect to net present values of future net revenue (forecast) as well as the cost escalation rates used for operating and capital costs are set forth below.

FORECAST PRICES & COST ESCALATION RATES USED IN D&M RESERVES REPORT[9]

	Conventional Natural Gas		Light and Medium Crude Oil		Cost Escalation
Year	TBNG (US$/Mcf)	Banarli (US$/Mcf)	TBNG (US$/bbl)	Banarli (US$/bbl)	%/year
2018	5.99	5.57	42.00	42.00	2.0
2019	6.09	5.66	44.25	44.25	2.0
2020	6.29	5.84	45.00	45.00	2.0
2021	6.49	6.03	45.68	45.68	2.0
2022	6.68	6.21	46.43	46.43	2.0
2023	6.78	6.30	47.10	47.10	2.0
2024	6.98	6.49	47.85	47.85	2.0
2025	7.18	6.67	48.60	48.60	2.0
2026	7.39	6.86	49.38	49.38	2.0
2027	7.59	7.06	50.16	50.16	2.0
2028	7.81	7.26	50.94	50.94	2.0
2029	8.04	7.47	51.72	51.72	2.0
2030	8.27	7.68	52.50	52.50	2.0

	Conventional Natural Gas		Light and Medium Crude Oil		Cost Escalation
Year	**TBNG (US$/Mcf)**	**Banarli (US$/Mcf)**	**TBNG (US$/bbl)**	**Banarli (US$/bbl)**	**%/year**
2031+	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter

The TBNG and Banarli conventional natural gas price forecast is based on gas sales from TBNG JV Lands and Banarli Licences realizing a price equivalent to 99% and 92% of the BOTAS reference price, respectively. The light and medium crude oil price forecast is based on liquid sales from TBNG JV Lands and Banarli Licences realizing a price equivalent to 75% of Brent pricing.

The Company's weighted average historical prices Canadian Dollars in Turkey for the year ended December 31, 2017 were:

Conventional Natural Gas ($/Mcf)	Light and Medium Crude Oil ($/bbl)	Natural Gas Liquids ($/bbl)
6.98	73.56	Not Applicable

RECONCILIATION OF THE COMPANY'S GROSS RESERVES BY PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS [9]

The following table sets forth a reconciliation of the changes in the Company's working interest, before royalties, of light and medium crude oil, heavy crude oil, conventional natural gas, natural gas liquids and oil equivalent reserves as at December 31, 2017 against such reserves as at December 31, 2016 based on the forecast price and cost assumptions set forth in Note 9:

	Light and Medium Crude Oil					Heavy Crude Oil				
	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Possible (Mbbl)	Gross Proved Plus Probable Plus Possible (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Possible (Mbbl)	Gross Proved Plus Probable Plus Possible (Mbbl)
At December 31, 2016	6	3	9	5	14	-	-	-	-	-
Extensions	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-2	-1	-3	-1	-4	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-
Acquisitions	4	1	5	1	6	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-
Production	3	-	3	-	3	-	-	-	-	-
At December 31, 2017	5	3	8	5	13	-	-	-	-	-

	Conventional Natural Gas					Natural Gas Liquids				
	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Possible (MMcf)	Gross Proved Plus Probable Plus Possible (MMcf)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Possible (Mbbl)	Gross Proved Plus Probable Plus Possible (Mbbl)
At December 31, 2016	9,363	18,803	28,166	15,125	43,291	-	-	-	-	-
Extensions	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-1,513	-1,642	-3,155	-1,080	-4,235	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-
Acquisitions	7,453	16,450	23,903	12,520	36,423	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-
Production	2,067	-	2,067	-	2,067	-	-	-	-	-
At December 31, 2017	13,236	33,611	46,847	26,565	73,412	-	-	-	-	-

	Oil Equivalent[10][17]				
	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved Plus Probable (Mboe)	Gross Possible (Mboe)	Gross Proved Plus Probable Plus Possible (Mboe)
At December 31, 2016	1,567	3,137	4,704	2,526	7,230
Extensions	-	-	-	-	-
Technical Revisions	-254	-275	-529	-181	-710
Discoveries	-	-	-	-	-
Acquisitions	1,246	2,743	3,989	2,088	6,077
Dispositions	-	-	-	-	-
Economic Factors	-	-	-	-	-
Production	348	-	348	-	348
At December 31, 2017	2,211	5,605	7,816	4,433	12,249

Notes:

(1) "**Gross Reserves**" are the Company's working interest (operating or non-operating) share before deducting royalties and without including any royalty interests of the Company. "**Net Reserves**" are the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in reserves.

(2) "**Proved**" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(3) "**Probable**" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(4) "**Possible**" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

(5) "**Developed**" reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production.

(6) "**Developed Producing**" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(7) "**Developed Non-Producing**" reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

(8) "**Undeveloped**" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

(9) The pricing assumptions used in the D&M Reserves Report with respect to net values of future net revenue (forecast) as well as the cost escalation rates used for operating and capital costs are set forth in the preceding table titled "Forecast Prices & Cost Escalation Rates Used in D&M Reserves Report". The Forecast Prices & Cost Escalation rates were developed by D&M as at December 31, 2017 and reflect the then current year forecast prices and cost escalation rates. D&M is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(10) "**boe**" means barrel of oil equivalent, derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(11) "**Mcfe**" means thousand cubic feet of sales gas equivalent derived by converting oil to gas in the ratio of one barrel of oil to six thousand cubic feet of gas. Mcfes may be misleading, particularly if used in isolation. A Mcfe conversion ratio of 1 bbl to 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(12) Including solution gas and other by-products associated with oil production.

(13) Including non-associated gas by-products but excluding solution gas.

(14) Reference to M US$, US$/bbl, US$/Mcf, US$/boe and US$/Mcfe are stated in United States Dollars. Reference to M$, $/bbl, $/Mcf, $/boe and $/Mcfe are stated in Canadian dollars.

(15) Income taxes are Turkey income taxes.

(16) The D&M Reserves Report categorizes all production as natural gas as the primary phase.

(17) Values may not add due to rounding.

Proved Undeveloped Reserves

The following table sets forth the volumes of proved undeveloped reserves that were first attributed for each of the Company's product types in each of the three most recent financial years:

	Light and Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	Oil Equivalent[(1)] (Mboe)
December 31, 2015	-	-	855	-	143
December 31, 2016	-	-	-	-	-
December 31, 2017	-	-	-	-	-

Note:

(1) "**boe**" means barrel of oil equivalent, derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil. Barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In the D&M Reserves Report as of December 31, 2017, there are no assigned proved undeveloped reserves first attributed in 2017.

In the D&M Reserves Report as of December 31, 2017, there are a total of 16 drilling locations assigned proved undeveloped reserves. The Company expects to develop the majority (15 of the 16 drilling locations) of these reserves over the next three years. The Company anticipates utilizing a portion of a one rig program over the next three years (2018 to 2020) in the development of these proved undeveloped reserves. The pace of development of these reserves can be influenced by many factors, including but not limited to, changing technical conditions, partner and regulatory approval, changes in product pricing, capital allocation priorities and the results of yearly drilling and reservoir evaluations. As new information becomes available these reserves are reviewed and drilling plans are revised accordingly.

Probable Undeveloped Reserves

The following table sets forth the volumes of probable undeveloped reserves that were first attributed for each of the Company's product types in each of the three most recent financial years:

	Light and Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	Oil Equivalent[(1)] (Mboe)
December 31, 2015	2	-	3,044	-	509
December 31, 2016	-	-	-	-	-
December 31, 2017	-	-	-	-	-

Note:

(1) "**boe**" means barrel of oil equivalent, derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil. Barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In the D&M Reserves Report as of December 31, 2017, there are no assigned probable undeveloped reserves first attributed in 2017.

In the D&M Reserves Report as of December 31, 2017, there are a total of 50 drilling locations assigned probable undeveloped reserves. The Company expects to develop the majority (48 of the 50 drilling locations) of these reserves over the next six years. The Company anticipates utilizing a portion of a one rig program over the next three years (2018 to 2020); scaling up to a one rig program in 202; a two rig program in 2022; and scaling back to a partial one rig program in 2023. The pace of development of these reserves can be influenced by many factors, including but not limited to, changing technical conditions, partner and regulatory approval, changes in product pricing, capital allocation priorities and the results of yearly drilling and reservoir evaluations. As new information becomes available these reserves are reviewed and drilling plans are revised accordingly.

Significant Factors or Uncertainties Affecting Reserves Data

There are a number of factors that could result in delayed or cancelled development of the Company's proved and probable undeveloped reserves, including the following: (i) partner and regulatory approvals; (ii) availability of equipment; (iii) product pricing; (iv) currency exchange rates; (v) well performance; and (vi) availability of financing in the future. Approximately 88% of the drilling locations (14 locations) assigned proved undeveloped reserves and 96% of the drilling locations (48 locations) assigned probable undeveloped reserves are in tight gas reservoirs located below the conventional shallow gas reservoirs in the Tekirdag field, which is located immediately adjacent to the growing city of Tekirdag. The Company expects that the process to achieve routine drilling location approvals from the Ministry of Energy and Natural Resources, the Ministry of Agriculture and the local landowners could take longer than experienced in the past and may require pad drilling operations, all of which could extend the current contemplated timelines of approximately three years and approximately six years for development of the proved undeveloped reserves and the probable undeveloped reserves, respectively.

Further to the timing of the development of proved undeveloped reserves, the Company envisages initially utilizing a portion of a one drilling rig program over the next three years (2018 to 2020) to develop the assigned proved undeveloped reserves over an approximate three-year timeline. Further to the timing of the development of probable undeveloped reserves, the Company envisages initially utilizing a portion of a one drilling rig program over the next three years (2018 to 2020), scaling up to a one drilling rig program in 2021, further scaling up to a two drilling rig program in the fifth year (2022) and scaling back to a one drilling rig program in the sixth year (2023) to develop the assigned probable undeveloped reserves over an approximate six-year timeline. This was felt to be a reasonable development pace given the large scale of the drilling program. Also, the pace reflects some extension to normal timelines for routine approvals of well locations by the Turkish authorities, recognizing that 88% of the drilling locations assigned proved undeveloped reserves and 96% of the drilling locations assigned probable undeveloped reserves (total of 62 drilling locations) are accessing unconventional tight gas reservoirs in the Tekirdag field, which is located immediately adjacent to the growing city of Tekirdag. The development timeline also enables learning and fine-tuning of well design and fracture stimulation design during the course of the program so as to improve cost efficiency and overall effectiveness.

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices, currency exchange rates and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of future net revenue there from. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effect of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, currency exchange rates, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in forecast prices, currency exchange rates, reservoir performance and geological conditions or production. These revisions can be either positive or negative. While the Company does not anticipate any significant economic factors or significant uncertainties will affect any particular component of the reserve data, the reserves can be affected significantly by fluctuations in product pricing, currency exchange rates, capital expenditures, operating costs, royalty regimes and well performance that are beyond the Company's control.

Future Development Costs

The following table sets forth the development costs deducted in the estimation of future net revenue attributable to each of the following reserves categories contained in the D&M Reserves Report:

	Total Proved(1) Estimated Using Forecast Prices and Costs (M US$)	Total Proved(1) Plus Probable(2) Estimated Using Forecast Prices and Costs (M US$)
2018	4,111	5,939
2019	10,508	11,434
2020	10,226	10,226
2021	2,096	22,591
2022	132	39,217
Remainder	14	25,281
Total for all years undiscounted	27,087	114,688

Notes:

(1) "**Proved**" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(2) "**Probable**" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

The Company's primary source of liquidity to fund its estimated future development costs, as outlined in the above table, is derived from one of or a combination of the Company's internally-generated cash flow, cash on hand, debt financing when deemed appropriate and new equity issues if made on favourable terms.

Oil and Gas Properties and Wells

The Company's major properties are the TBNG JV Lands and Banarli Licences both situated in the Thrace Basin. The Company also holds interests in three production leases at Edirne in the Thrace Basin which is considered a minor property. In total the Company's land holdings as of December 31, 2017 comprised an onshore area of approximately 826 gross sections (approximately 675 net sections from surface to 2500 metres and approximately 435 net sections below 2500 metres) all in Turkey. These areas assume Statoil completes its earning of a 50% interest in the deep rights (below 2500 metres) on the Banarli Licences. All of the Company's 2017 production was from the Thrace Basin.

As of December 31, 2017, the TBNG JV Lands entailed 14 production leases and two exploration licences comprising an onshore area of approximately 539 gross sections (approximately 439 net sections from surface to 2500 metres and approximately 303 net sections below 2500 metres). All development is onshore and a small percentage of the acreage is developed. Nine of the 14 production leases and both of the exploration licences on the TBNG JV Lands are new production leases and exploration licences that were converted under the New Petroleum Law.

As of December 31, 2017, the Banarli Licences entailed two exploration licences comprising an onshore area of approximately 209 gross sections (approximately 209 net sections from surface to 2500 metres and approximately 104 net sections below 2500 metres). These areas assume Statoil completes its earning of a 50% interest in the deep rights (below 2500 metres) on the Banarli Licences. The Banarli Licences are new exploration licences that were converted under the New Petroleum Law.

As of December 31, 2017, the Edirne Lands entailed three production leases comprising an onshore area of approximately 78 gross sections (approximately 27 net sections). The Edirne production leases are new production leases that were converted under the New Petroleum Law.

The natural gas produced in the Thrace Basin has a high methane content and is relatively dry with a low water to gas ratio which currently only requires dehydration and compression to meet sales requirements. The Company has an extensive gas gathering network which gathers all the production to a central dehydration and compression facility. Processed natural gas is delivered through a TBNG JV owned distribution network to 55 customers within a 50 kilometres distance of TBNG JV's central processing facility.

A listing of the Company's wells in Turkey as of December 31, 2017 is shown below:

	Oil Wells		**Natural Gas Wells**		**Standing & Other Wells**	
	Gross(1)	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**
Producing	1	0.82	90	73.54	0	0.00
Non-producing	0	0.00	132	102.80	25	20.25
Total	1	0.82	222	176.34	25	20.25

Notes:

(1) "**Gross Wells**" are the total number of wells in which the Company has an interest.
(2) "**Net Wells**" are the number of wells obtained by aggregating the Company's working interest in each of its gross wells.

Properties with No Attributed Reserves

The following table sets out the Company's undeveloped land position in Turkey effective December 31, 2017:

	Undeveloped Acreage			
	Shallow Acreage (surface to a depth of 2500 metres)		**Deep Acreage (a depth of 2500 metres and deeper)**	
	Gross(1)	**Net(2)**	**Gross(1)**	**Net(2)**
Thrace Basin	515,338	422,084	527,081	277,629
Total	515,338	422,084	527,081	277,629

Notes:

(1) "**Gross**" means the total number of acres in which the Company has a working interest.
(2) "**Net**" means the number of acres obtained by aggregating the Company's working interest in each of its acreage positions.

The above table assumes Statoil completes its earning of a 50% working interest in the deep rights on Banarli Licences. No net undeveloped acreage is expected to expire in 2018.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

At this time the Company has not completed an independent evaluation of its undeveloped acreage in Turkey. However, the Company has completed an independent assessment of its prospective resources on the TBNG JV Lands and the Banarli Licences effective December 31, 2017 which identified significant undiscovered prospective resources potential. See "*Appendix A-2 – Prospective Resources Data*" for a summary of the prospective resources evaluated by D&M in the D&M Resources Report and for details regarding risked estimates.

Forward Contracts

Currently there are no material forward contracts or commitments.

Abandonment and Reclamation Costs

All wells assigned reserves as well as unabandonned wells that have not been assigned reserves are included in the D&M Reserves Report and are assigned abandonment and reclamation costs.

Abandonment and reclamation costs are estimated on an area by area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment and reclamation requirements. The Company has 197.4 net wells as of December 31, 2017 for which abandonment and reclamation costs are expected to be incurred.

In the D&M Reserves Report the total well abandonment cost in respect of proved reserves using Forecast Prices and Costs are US$8.4 million (undiscounted). All of this amount was deducted as abandonment and reclamation costs in estimating the Company's future net revenue as disclosed above.

In the D&M Reserves Report well abandonment and reclamation costs for all wells with reserves as well as unabandonned wells that have not been assigned reserves have been included at the property level. Additional abandonment and reclamation costs associated with facility abandonment and reclamation expenses have not been included in this analysis.

Tax Horizon

The Company paid cash income taxes in Turkey for the period ended December 31, 2017, mostly due to tax on farm-in proceeds received. Based on current estimates of the Company's future taxable income and expected future capital expenditures, management believes that the Company will not be required to pay cash income taxes in Turkey in 2018.

Costs Incurred

The following table summarizes the capital expenditures made by the Company on oil and natural gas properties in Turkey for the year ended December 31, 2017:

	Property Acquisition (Disposition) Costs(14) (M$)		**Exploration Costs(14) (M$)**	**Development Costs(14) (M$)**
	Proved Properties	**Unproved Properties**		
TBNG JV Lands	21,450	(3,973)	4,541	5,235
Banarli Licences	-	(22,315)	2,377	638
Other	-	-	-	-
Total Turkey	21,450	(26,228)	6,918	5,873

Note:

See Notes that follow the table titled "*Reconciliation of the Company's Gross Reserves by Principal Product Type Based on Forecast Prices and Costs*".

Exploration and Development Activities

The following table sets forth the number of wells the Company drilled for the year ended December 31, 2017 in Turkey (the Company did not drill any service wells or stratigraphic test wells):

	Exploratory Wells		**Development Wells**	
	Gross(1)(2)(3)	**Net(1)(2)(3)**	**Gross(1)(2)(3)**	**Net(1)(2)(3)**
Oil Wells	0	0.00	0	0.00
Gas Wells	1	0.50	3	2.45
Standing & Other Wells	2	1.81	0	0.00
Dry Holes	1	0.82	0	0.00
Total Wells	4	3.13	3	2.45

Notes:

(1) "**Gross Wells**" are the total number of wells in which the Company has an interest.
(2) "**Net Wells**" are the number of wells obtained by aggregating the Company's working interest in each of its gross wells.
(3) Spud date is the criteria the Company uses to categorize drilled wells by year.

See "*Description of the Business and Operations*" in the Annual Information Form for a general description of Valeura's most important current and likely exploration and development activities.

Production Estimates

The following table sets forth the volume of working interest daily production, before royalties, estimated for 2018 which is reflected in the estimate of future net revenue disclosed in the tables of reserve information in respect of gross proved and probable reserves in Turkey:

	Light and Medium Crude Oil (bbl/d)	Heavy Crude Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)
Proved Developed Producing(2)(6)				
TBNG JV Lands	5	-	4,137	-
Banarli Licences	1	-	247	-
Total Proved Developed Producing	6	-	4,384	-
Proved Developed Non-Producing(2)(7)				
TBNG JV Lands	-	-	574	-
Banarli Licences	-	-	-	-
Total Proved Developed Non-Producing	-	-	574	-
Proved Undeveloped(2)(8)				
TBNG JV Lands	-	-	434	-
Banarli Licences	-	-	-	-
Total Proved Undeveloped	-	-	434	-
Total Proved(2)				
TBNG JV Lands	5	-	5,145	-
Banarli Licences	1	-	247	-
Total Proved	6	-	5,392	-
Total Probable(3)				
TBNG JV lands	1	-	531	-
Banarli Licences	-	-	251	-
Total Probable	1	-	782	-
Total Proved Plus Probable(2)(3)				
TBNG JV Lands	6	-	5,676	-
Banarli Licences	1	-	498	-
Total Proved Plus Probable	7	-	6,174	-

Note: See Notes that follow the table titled "*Reconciliation of the Company's Gross Reserves by Principal Product Type Based on Forecast Prices and Costs*".

Production History

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by the Company for each quarter of its most recently completed financial year for properties in Turkey:

	Three Months Ended March 31, 2017	Three Months Ended June 30, 2017	Three Months Ended September 30, 2017	Three Months Ended December 31, 2017
Average Daily Production				
Light and Medium Crude Oil (bbl/d)	3	9	11	9
Conventional Natural Gas (Mcf/d)	4,825	5,550	6,077	6,176
boes (boe/d)	807	934	1,024	1,039
Average Prices Received				
Light and Medium Crude Oil ($/bbl)(14)	72.83	68.39	65.16	82,78
Conventional Natural Gas ($/Mcf)(14)	7.06	7.34	6.98	6.61
boes ($/boe)(14)	42.49	44.28	42.14	40.03
Royalties				
Light and Medium Crude Oil ($/bbl)(14)	14.34	9.43	4.58	9.05
Conventional Natural Gas ($/Mcf)(14)	0.91	1.03	0.94	0.89
boes ($/boe)(14)	5.50	6.20	5.62	5.39
Production Costs				
Light and Medium Crude Oil ($/bbl)(14)	11.10	4.86	4.83	6.49
Conventional Natural Gas ($/Mcf)(14)	1.39	2.63	2.33	2.06
boes ($/boe)(14)	8.37	15.70	13.86	12.29
Netback Received				
Light and Medium Crude Oil ($/bbl)(14)	47.39	54.10	55.75	67.24
Conventional Natural Gas ($/Mcf)(14)	4.76	3.68	3.72	3.66
boes ($/boe)(14)	28.62	22.38	22.66	22.34

Note:

See Notes that follow the table titled "*Reconciliation of the Company's Gross Reserves by Principal Product Type Based on Forecast Prices and Costs*".

The following table sets forth certain information in respect of production that is included in the preceding table and is attributable to TBNG JV Lands:

	Three Months Ended March 31, 2017	Three Months Ended June 30, 2017	Three Months Ended September 30, 2017	Three Months Ended December 31, 2017
Average Daily Production				
Light and Medium Crude Oil (bbl/d)	3	9	10	6
Conventional Natural Gas (Mcf/d)	3,528	4,954	5,644	5,793
boes (boe/d)	591	834	950	972

APPENDIX A-2 – PROSPECTIVE RESOURCES DATA

PROSPECTIVE RESOURCES DATA

(Capitalized terms not specifically defined in this Appendix A-2 have the meaning ascribed to them in the Annual Information Form to which this Appendix A-2 is attached)

The Company engaged D&M to prepare a report relating to the Company's prospective resources in Turkey as at December 31, 2017. The prospective resources on the properties described herein are estimates only. Actual prospective resources on these properties may be greater or less than those estimated.

The D&M Resources Report was prepared using the guidelines outlined in the COGE Handbook and in accordance with NI 51-101.

Teslimkoy/Kesan Basin-Centered Gas Prospect

D&M evaluated the unconventional prospective resources attributable to the Teslimkoy/Kesan basin-centered gas prospect on the Company's lands in the Thrace Basin. The working interest lands included comprise the deep formations (generally below 2,500 metres depth) on the Banarli Licenses (50% working interest), West Thrace lands (31.5% working interest) and South Thrace lands (81.5% working interest).

The D&M evaluation benefited from the Yamalik-1 natural gas-condensate discovery, which was drilled and flow tested on the Banarli Licenses in 2017. Yamalik-1 discovered an approximate 1,300 metres column of natural gas and condensate in over-pressured reservoirs below 2,900 metres in the Teslimkoy and Kesan formations. The well was drilled to 4,196 metres, fracture stimulated and production tested in Q4 2017. As announced on December 27, 2017, four production tests from eight frac stages in the Kesan formation yielded a 24-hour aggregate test rate of 2.9 MMcf/d. Extensive coring and wireline logging information was also captured in the well.

Yamalik-1 was the first well to be extensively facture stimulated in the basin-centered gas prospect in the Thrace Basin. However, well data from seven other legacy wells drilled in the prospective area to depths up to 4,050 metres also indicate over-pressured natural gas below approximately 2,500 metres and were available for D&M's evaluation. Only one of these legacy wells (Yayli-1) was fracture stimulated with a small two-stage frac at a depth of approximately 2,800 metres.

First commercial production of the Company's prospective resources in the Thrace Basin from the Yamalik-1 well is targeted for Q3 2018 at an anticipated cost of approximately US$4.0 million (gross). Hydraulic fracturing technology is required to evaluate the prospective resources, and the Company's current development plans with respect to such prospective resources are based on a conceptual study.

COMPANY WORKING INTEREST NATURAL GAS PROSPECTIVE RESOURCES(6)(7)(8)(9)(10)(12)(15)

The following table summarizes D&M's estimates of the Company's working interest prospective natural gas resources (defined as "conventional natural gas" under NI 51-101) as at December 31, 2017. These numbers as reported by D&M are for the complete gas stream and explicitly include condensate resources (defined as "natural gas liquids" under NI 51-101) which are entrained in the natural gas. Sales gas volumes would be nominally lower than those presented below. The table shown in the section below titled "*Company Working Interest Natural Gas Liquids Prospective Resources*" summarizes the amount of condensate as at December 31, 2017 that would be recovered in association with the production of the natural gas volumes shown below.

Company Working Interest Lands (1)	Unrisked Low Estimate (2) Gross (Bcf)	Unrisked Best Estimate (3) Gross (Bcf)	Unrisked High Estimate (4) Gross (Bcf)	Unrisked Mean Estimate (5) Gross (Bcf)	Chance of Commerciality % (11)	Risked Mean Estimate (12) Gross (Bcf)
Total	3,229	7,652	20,077	10,137	51.1	5,182

The broad range of recoverable gas from 3.2 to more than 20 Tcf is a function of the uncertainty in the various components of the assessment including recovery factor. There has been very limited stimulation and production testing from the over-pressured Teslimkoy and Kesan formations in the Thrace Basin, and as yet there is no production data. To determine potential recovery factors, D&M have utilized their experience in analogous basins. The prospective resources in above and below tables assume a low, best, high and mean estimate recovery factor of approximately 25%, 40%, 55% and 40% respectively. Significantly more delineation drilling, stimulation, and testing will be required to confirm that gas can be commercially recovered from the prospect, and to generate type curves that can be used in a predictive sense.

COMPANY WORKING INTEREST NATURAL GAS LIQUIDS PROSPECTIVE RESOURCES(6)(7)(8)(9)(10)(13)(14)(15)

The following table summarizes the amount of condensate as at December 31, 2017 that would be recovered in association with the production of the natural gas volumes summarized in the table shown above in the section titled "*Company Working Interest Natural Gas Prospective Resources*".

Company Working Interest Lands (1)	Unrisked Low Estimate (2) Gross (MMbbl)	Unrisked Best Estimate (3) Gross (MMbbl)	Unrisked High Estimate (4) Gross (MMbbl)	Unrisked Mean Estimate (5) Gross (MMbbl)
Total	45	155	504	236

Chance of Commerciality

D&M has assigned a chance of discovery of 70%. This high chance is driven by: (1) the hundreds of legacy wells drilled in the Thrace Basin which support the geological model for the Teslimkoy and Kesan formations; (2) the over-pressured natural gas which was encountered and tested at Yamalik-1, and (3) the seven legacy wells surrounding the basin which all encountered over-pressured gas below 2,500 metres.

D&M has assigned a chance of development of the natural gas prospective resources of approximately 74%, which is a product of the probability of threshold economic field size and probability of development. This high chance of development reflects that existing hydraulic fracturing technology is being applied, well depths and costs are not expected to be excessive, sales pipeline infrastructure already exists in the area and there are ready domestic markets in Turkey for domestic natural gas and condensate sales.

This results in an overall chance of commerciality of 51.1% which is the product of chance of discovery and chance of development. The resulting risked mean estimate of 5.2 Tcf of conventional natural gas prospective resources is shown section titled "*Company Working Interest Natural Gas Prospective Resources*" table is risked for chance of commerciality.

Significant Positive and Negative Factors Relevant to the Prospective Resources Estimate

Understanding of the extent of this basin-centered gas prospect in the Thrace Basin and its potential commerciality is in the early stages of exploration and appraisal. There are a number of positive and negative factors which are driving large uncertainty.

Positive factors with respect to the estimate of prospective resources include:

- Design work is underway for the production facilities and gathering pipeline to tie-in the Yamalik-1 well to the Company's existing gathering sales pipeline infrastructure to enable a long-term production test and natural gas and condensate sales from the well at an anticipated cost of approximately US$4 MM (gross). First sales from Yamalik-1 are targeted for Q3 2018.

- The Company and Statoil are planning a delineation drilling program comprising three wells expected to commence in Q3 2018 and extend into 2019. The first well in this program will be the second and final earning well under Phase 3 of the Banarli Farm-in to be fully funded by Statoil.

- The follow-up delineation drilling program will benefit from the new Karaca 3D seismic in terms of finalizing drilling locations, correlating the seismic to the Yamalik-1 well results and targeting sweet-spots in the basin-centered gas prospect.

- It is expected that the follow-up delineation wells will be drilled to approximately 5,000 metres given good potential to extend the column of hydrocarbon-bearing sands. The Yamalik-1 well was drilled to 4,196 metres, the limit of the rig capability and well completion, but the base of the well was still in gas-bearing sands that were successfully flow tested.

- The Company's existing infrastructure and customer base is expected to be capable of handling sales of more than 35 MMcf/d compared to current sales through the system of less than 10 MMcf/d, thereby providing the opportunity for early production from any future delineation wells.

- Turkey is a captive natural gas market given that 99% of its natural gas demand is served by imports. This provides an attractive marketing opportunity for a domestic natural gas producer. As the Company's natural gas production volumes potentially grow beyond the limit of its owned infrastructure, there are multiple take-away opportunities. These include: a potential to tie-in to a pipeline owned by BOTAS just north of the Banarli lands; a tie-in to another BOTAS interconnector pipeline traversing Banarli and connected to an export line to Greece; and sales to the local gas distributor who currently offtakes gas from the BOTAS pipeline to the north.

- Natural gas prices in Turkey are strong. The Company's average natural gas price realization in Q4 2017 was approximately CAD$6.61/Mcf. On January 1, 2018, the BOTAS reference price was increased by 14%.

Negative factors with respect to the estimate of prospective resources include:

- The basin-centered gas prospect is in the early exploration and delineation cycle with very sparse well control and very limited fracture stimulation and testing data.

- There is no long-term well production performance from the basin-centered prospect to establish a production type curve specific to the prospect, thereby requiring use of analogue information at this time to establish development plans and to confirm the chance of commerciality.

- Recovery efficiencies are uncertain given the absence of site specific long-term well production performance data in the basin-centered gas prospect.

- The limited deep drilling carried out in the Thrace Basin provides poor visibility on future costs to drill, frac and complete deep development wells to exploit the basin-centered gas prospect and the associated impact on the chance of commerciality.

- Although oil and gas activity has been underway for many decades in the Thrace Basin area, as activity levels increase, timelines may increase to achieve government and local landowner approvals.

Readers should also review the "*Risk Factors*" section in the Annual Information Form for a broader discussion of the risks and uncertainties facing the Company.

Notes:

(1) The Company's working interest in the lands (exploration licences and production leases) that are encompassed (all or a portion thereof) in the basin-centered gas prospect in the Teslimkoy/Kesan formation is as follows: Banarli Licneses 50%, West Thrace Lands 31.5% and South Thrace Lands 81.5%.
(2) The low estimate is the P_{90} quantity. P_{90} means there is a 90% chance that the estimated quantity will be equaled or exceeded.
(3) The best estimate is the P_{50} quantity. P_{50} means there is a 50% chance that the estimated quantity will be equaled or exceeded.
(4) The high estimate is the P_{10} quantity. P_{10} means there is a 10% chance that the estimated quantity will be equaled or exceeded.
(5) The mean estimate is the probability-weighted average (expected value).
(6) The totals are the arithmetic summation of probabilistic estimates. Arithmetic summation may produce invalid results except for the mean.
(7) Unconventional prospective resources, as prepared by D&M, are those quantities of petroleum that are estimated, at a given date, to be potentially recoverable from undiscovered unconventional accumulations by application of future development projects. Unconventional prospective resources may exist in petroleum accumulations that are pervasive throughout a large potential production area and would not be significantly affected by hydrodynamic influences (also called continuous-type deposits). Typically such accumulations (once discovered) require specialized extraction technology (e.g. massive fracturing programs for tight gas). Tight gas occurs within low permeability reservoir rocks, which are rocks with matrix porosity of 10 percent or less and permeability of 0.1 millidarcies or less, exclusive of fractures. Tight gas can be regionally distributed (e.g. the basin-centered gas prospect in the Thrace Basin evaluated herein), rather than accumulated in a readily producible reservoir in a discrete structural closure as in a conventional gas field.
(8) Prospective resources have both an associated *chance of discovery* and a *chance of development*. There is no certainty that any portion of the unconventional prospective resources estimated herein will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the unconventional prospective resources evaluated. Estimates of the unconventional prospective resources should be regarded only as estimates that may change as additional information becomes available. Not only are such unconventional prospective resources estimates based on that information which is currently available, but such estimates are also subject to uncertainties inherent in the application of judgmental factors in interpreting such information. Unconventional prospective resources should not be confused with those quantities that are associated with contingent resources or reserves due to the additional risks involved. Because of the uncertainty of commerciality and the lack of sufficient exploration drilling, the unconventional prospective resources estimated herein cannot be classified as contingent resources or reserves. The quantities that might actually be recovered, should they be discovered and developed, may differ significantly from the estimates herein.
(9) The unconventional prospective resources estimates contained in the D&M Resources Report are expressed as gross and working interest unconventional prospective resources. The above tables summarize Valeura's working interest unconventional prospective resources, which incorporate the fraction of potential hydrocarbon pore volume owned or partially owned by the Company and the Company's working interest ownership, before deduction of any associated royalty burdens. Recovery efficiency is applied to unconventional prospective resources in the above tables.
(10) The estimation of resources quantities for a prospect is subject to both technical and commercial uncertainties and, in general, may be quoted as a range. The range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities. Estimates of petroleum resources herein are expressed using the terms low estimate, best estimate, high estimate and mean estimate (unrisked and risked) to reflect the range of uncertainty.
(11) The chance of commerciality is defined as the product of the *chance of discovery* and the *chance of development*. *Chance of discovery* is defined in COGE Handbook as the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. *Chance of development* is the estimated probability that, once discovered, a known accumulation will be commercially developed.
Chance of discovery in the D&M Resources Report is referred to as the probability of geologic success (P_g), which is defined as the probability of discovering reservoirs that flow hydrocarbons at a measureable rate. The P_g is estimated by quantifying with a probability, each of the following geologic chance factors: trap, source, reservoir and migration. The product of the probabilities of these four chance factors is P_g. P_g is predicated and correlated to the minimum case prospective resources gross recoverable volume(s). Consequently, the P_g is not linked to economically viable volumes, economic flow rates or economic field size distributions.
In the D&M Resources Report, two factors have been considered in determining the *chance of development* as follows:
Chance of development = P_{tefs} (probability of threshold economic field size) x P_d (probability of development)
D&M defines P_{tefs} as the probability of discovering an accumulation that is large enough to be economically viable. P_{tefs} is estimated by using the prospective resources potential recoverable quantities distribution in conjunction with the threshold economic field size (TEFS). TEFS is the minimum amount of the producible petroleum required to recover the total capital and operating expenditure used to establish the potential accumulation as having a potential present worth at 10% equal to zero using the most likely price scenario.
D&M defines P_d as the probability that a given discovery will be a viable development project. It takes into account the chance that the discovered target zone will flow the predicted hydrocarbon phase(s) at a commercial rate. It also considers the chance that the target zone can be mechanically completed and appraised in a reasonable time and in compliance with the projected cost schedule. The P_d is estimated by the quantification and product of these two chance factors.
(12) The risked mean estimate of conventional natural gas prospective resources = the unrisked mean estimate x *chance of discovery* x *chance of development*.

(13) The conventional natural gas (raw gas in the D&M Resources Report) is the total gas produced from the reservoir prior to processing or separation and includes all non hydrocarbon components as well as any gas equivalent of condensate.
(14) The natural gas liquids prospective resources are included in the conventional natural gas prospective resources.
(15) "Gross Prospective Resources" are the Company's working interest (operating or non-operating) share before deducting royalties and without including any royalty interests of the Company. "Net Prospective Resources" are the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in prospective resources.

APPENDIX A-3 – FORM 51-101F2 – REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

APPENDIX A-4 – FORM 51-101F2 – REPORT ON PROSPECTIVE RESOURCES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

APPENDIX A-5 – FORM 51-101F3 - REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

FORM 51-101F3

REPORT OF
MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Valeura Energy Inc., (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data and includes other information such as prospective resources data.

An independent qualified reserves evaluator has evaluated the Company's reserves data and prospective resources data. The reports of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data and prospective resources data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data, prospective resources data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data or the prospective resources data; and

(c) the content and filing of this report.

Because the reserves data and the prospective resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

March 20, 2018

(signed) "*Sean Guest*"
Sean Guest
President and Chief Executive Officer

(signed) "*Don Shepherd*"
Don Shepherd
Vice President, Engineering

(signed) "*Ronald Royal*"
Ronald Royal
Director and Chairman of Reserves Committee

(signed) "*Timothy Marchant*"
Timothy Marchant
Director and Member of Reserves Committee

APPENDIX B – TERMS OF REFERENCE FOR THE AUDIT COMMITTEE

APPENDIX B

TERMS OF REFERENCE FOR THE AUDIT COMMITTEE

I. PURPOSE

The primary function of the Audit Committee (the "**Committee**") is to assist the Board in fulfilling its oversight responsibilities by reviewing:

A. the financial information that will be provided to the shareholders and others;

B. the systems of internal controls, management and the Board of Directors have established; and

C. all audit processes.

Primary responsibility for the financial reporting, information systems, risk management and internal controls of Corporation is vested in management and is overseen by the Board.

II. COMPOSITION AND OPERATIONS

A. The Committee shall be composed of not fewer than three directors and not more than five directors, all of whom are independent[1] directors of the Corporation.

B. All Committee members shall be "financially literate"[2] and at least one member shall have "accounting or related financial expertise". The Committee may include a member who is not financially literate, provided he or she attains this status within a reasonable period of time following his or her appointment and providing the Board has determined that including such member will not materially adversely affect the ability of the Committee to act independently.

C. The Committee shall operate in a manner that is consistent with the Committee Guidelines outlined in Tab 7 of the Board Manual.

D. The Corporation's auditors shall be advised of the names of the committee members and will receive notice of and be invited to attend meetings of the Audit Committee, and to be heard at those meetings on matters relating to the Auditor's duties.

E. The Committee has the authority to communicate with the external auditors as it deems appropriate to consider any matter that the Committee or auditors determine should be brought to the attention of the Board or shareholders.

F. The Committee shall meet at least four times each year.

---

1 Independence requirements are described in the Appendix to Tab 5, Board Operating Guidelines.

2 The Board has adopted the NI 52-110 definition of "financial literacy", which is an individual is financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the issuer's financial statements.

III. Duties and Responsibilities

Subject to the powers and duties of the Board, the Committee will perform the following duties:

A. *Financial Statements and Other Financial Information*

The Committee will review and recommend for approval to the Board financial information that will be made publicly available. This includes:

i) review and recommend approval of the Corporation’s annual financial statements and MD&A and report to the Board of Directors before the statements are approved by the Board of Directors;

ii) review and approve for release the Corporation’s quarterly financial statements and press release;

iii) satisfy itself that adequate procedures are in place for the review of the public disclosure of financial information extracted or derived from the Corporation’s financial statements, other than the public disclosure referred to in items (i) and (ii) above, and periodically assess the adequacy of those procedures; and

iv) review the Annual Information Form and any Prospectus/Private Placement Memorandums.

Review and discuss:

v) the appropriateness of accounting policies and financial reporting practices used by the Corporation;

vi) any significant proposed changes in financial reporting and accounting policies and practices to be adopted by the Corporation;

vii) any new or pending developments in accounting and reporting standards that may affect the Corporation;

viii) review with management, the external auditors and, if necessary, legal counsel, any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Corporation, and the manner in which these matters may be, or have been, disclosed in the financial statements; and

ix) review accounting, tax and financial aspects of the operations of the Corporation as the Committee considers appropriate.

B. *Risk Management, Internal Control and Information Systems*

The Audit Committee will review and obtain reasonable assurance that the risk management, internal control and information systems are operating effectively to produce accurate, appropriate and timely management and financial information. This includes:

i) review the Corporation’s risk management controls and policies;

ii) obtain reasonable assurance that the information systems are reliable and the systems of internal controls are properly designed and effectively implemented through discussions with and reports from management, the internal auditor and external auditor; and

iii) review management steps to implement and maintain appropriate internal control procedures including a review of policies.

C. ***External Audit***

The External Auditor is required to report directly to the Committee, which will review the planning and results of external audit activities and the ongoing relationship with the external auditor. This includes:

i) review and recommend to the Board, for shareholder approval, engagement and compensation of the external auditor;

ii) review and approve the annual external audit plan, including but not limited to the following:

   a) engagement letter;

   b) objectives and scope of the external audit work;

   c) procedures for quarterly review of financial statements;

   d) materiality limit;

   e) areas of audit risk;

   f) staffing;

   g) timetable; and

   h) approve fees;

iii) meet with the external auditor to discuss the Corporation's quarterly and annual financial statements and the auditor's report including the appropriateness of accounting policies and underlying estimates;

iv) maintain oversight of the External Auditor's work and advise the Board, including but not limited to:

   a) the resolution of any disagreements between management and the External Auditor regarding financial reporting;

   b) any significant accounting or financial reporting issue;

   c) the auditors' evaluation of the Corporation's system of internal controls, procedures and documentation;

   d) the post audit or management letter containing any findings or recommendation of the external auditor, including management's response thereto and the subsequent follow-up to any identified internal control weaknesses;

   e) any other matters the external auditor brings to the Committee's attention; and

   f) assess the performance and consider the annual appointment or re-appointment of external auditors for recommendation to the Board ensuring that such auditors are participants in good standing pursuant to applicable regulatory laws;

v) review the auditor's report on all material subsidiaries;

vi) review and discuss with the external auditors all significant relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence, including, without limitation:

a) requesting, receiving and reviewing, on a periodic basis, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to the Corporation;

b) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors; and

c) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence;

vii) review and pre-approve any non-audit services to be provided by the external auditor's firm or its affiliates (including estimated fees), and consider the impact on the independence of the external audit; and

viii) meet periodically, and at least annually, with the external auditor without management present.

D. *Compliance*

The Committee shall:

i) ensure that the External Auditor's fees are disclosed by category in the Annual Information Form in compliance with regulatory requirements;

ii) disclose any specific policies or procedures the Corporation has adopted for pre-approving non-audit services by the External Auditor including affirmation that they meet regulatory requirements;

iii) assist the Governance and Compensation Committee with preparing the Corporation's governance disclosure by ensuring it has current and accurate information on:

a) the independence of each Committee member relative to regulatory requirements for audit committees;

b) the state of financial literacy of each Committee member, including the name of any member(s) currently in the process of acquiring financial literacy and when they are expected to attain this status; and

c) the education and experience of each Committee member relevant to his or her responsibilities as Committee member;

iv) disclose if the Corporation has relied upon any exemptions to the requirements for Audit Committees under regulatory requirements.

E. ***Other***

The Committee shall:

i) establish and periodically review implementation of procedures for:

   a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters; and

   b) the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters;

ii) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former External Auditor;

iii) review insurance coverage of significant business risks and uncertainties;

iv) review material litigation and its impact on financial reporting;

v) review policies and procedures for the review and approval of officers' expenses and perquisites;

vi) review policies and practices concerning the expenses and perquisites of the Chairman, including the use of the assets of the Corporation;

vii) review with external auditors any corporate transactions in which directors or officers of the Corporation have a personal interest;

viii) review the terms of reference for the Committee annually and make recommendations to the Board as required;

ix) review list of gifts and entertainment expenses and other matters contemplated under the Anti-Corruption Policy; and

x) review the adequacy of the Anti-Corruption Policy and report on its implementation and matters arising thereunder to the Board.

IV. ACCOUNTABILITY

A. The Committee Chair has the responsibility to make periodic reports to the Board, as requested, on financial matters relative to the Corporation.

B. The Committee shall report its discussions to the Board by maintaining minutes of its meetings and providing an oral report at the next Board meeting.